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Price Behaviors in Deregulated Power Markets

by

Ying Li ©

A thesis submitted to the Faculty of Graduate Studies and Research in partial fulfillment of the

requirements for the degree of *Doctor of Philosophy*

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Dedicated to

my parents Shujuan and Jisheng and my beloved Lue

for their love, encouragement, and support.

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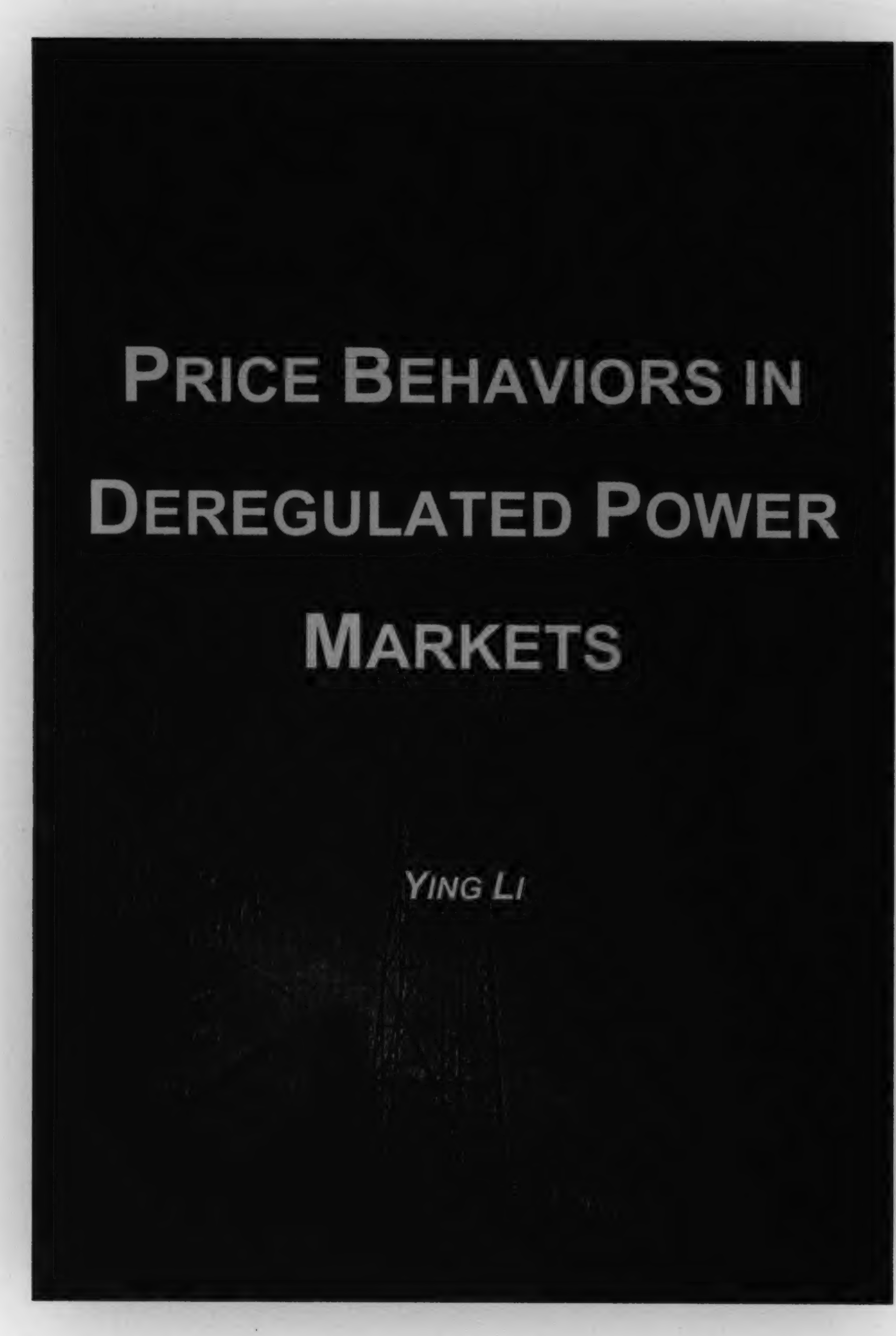

PRICE BEHAVIORS IN DEREGULATED POWER MARKETS

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CHAPTER 1 INTRODUCTION

1.1 Research Motivation

Over the past decade the electric power industry in many countries has experienced a wave of structural change. Many power markets have been deregulated and moved to hourly or half-hourly adjustment of power price through a bidding process. In an effort to ensure a fair and open market, deregulated markets have usually started with a single mandated clearing pool through which all wholesale electric power is sold, giving a single price[1] for the commodity at any point in time. The electric utility market has ceased to be a safe and protected haven for investors and a stable price environment for consumers. The introduction of market forces resulted in the removal of guaranteed rates of return for the shareholders and in open competition for wholesale and retail consumers. Both power consumers and power producers are facing a higher level of financial risks.

Electric power is a basic commodity in an industrialized society, used in virtually all aspects of life. However, it cannot be practically stored in significant quantities, and cannot be economically transported for long distances. Other energy commodities are transportable, for example, oil, and hence tend to have a single world price that varies between regions only due to transportation costs. Electricity, on the other hand, can have completely different prices in different geographical areas, since movement of the commodity from one region to another is often not economic or even practical. For instance, a severe shortage of power in New Zealand, as occurred during a period of unusual drought, led to prices and price patterns that were completely independent of power prices in Australia.

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[1] In deregulated markets, hedging arrangements are often made in parallel to purchases from the central clearing pool. In effect, a generator and a distributor or consumer agree to a price, and settle the difference between the agreed price and the pool price by periodic remittance of the difference. These so-called contracts for difference (CFD) are mechanisms for allocating part of existing financial risk without trading in power.

The fact that electricity is not storable also leads to high hourly variations in price in deregulated markets. This again makes electricity unlike other commodities: it is not unusual for electric power to show both a significant daily variation in price as well as a large variation in average price between days. Changing market structures, uncertainty in future regulatory structures, competitive behaviors in the market, and high volatility of markets are some of the effects not previously seen in regulated markets, and this has created a desire for a better understanding and forecasting of power price. For these reasons, power price in deregulated markets provides a unique opportunity to study inter-market variations in the price of a basic commodity.

1.2 Research Focus

In a regulated power market, the regulatory approval of cost based price sends a signal to generators: a plant that is approved will receive a price that ensures a fair return to investors provided the unit is operated in a prudent and non-negligent manner. In a deregulated power market, power price, which is no longer cost based, continues to send signals to power generators as well. These signals appear to be clear, in that new generation is commissioned in response to high prices. In an ideal deregulated market power price would guide the actions of consumers as well as generators, i.e., at least some consumers would shape their consumption of power to reflect the price.

For price to send a signal to consumers to shift short term consumption behaviors it has to be comprehensible; markets that appear to be chaotic and random would lead a power consumer to hedge uncertainty by locking in an average power price. Once this action is taken, the consumer has no incentive to further shape consumption behaviors.

The focus of this research has, from its inception, been from the perspective of power customers. What sense can a power consumer make of daily power price patterns? Can the informed consumer make intelligent decisions about future actions, including demand side management (DSM) of consumption activities, financial hedging etc., based on the information contained in those patterns? The findings emerging from this research show that some deregulated power markets are more comprehensible to power consumers than others.

1.3 Research Methodology

Hourly or half-hourly power price data were collected from a number of deregulated wholesale spot power markets. Short-term and long-term variations in power price, in terms of average diurnal pattern, volatility, and changes over time of power price, are explored for many deregulated power markets to determine if there are significant differences between the markets. Diurnal pattern of power price is studied by averaging hourly or half-hourly prices; price volatility is investigated by examining the average daily change in price, i.e., price velocity; price evolution is explored by looking at the changes of diurnal pattern and volatility of power price over time within individual markets.

The price data studied are from deregulated wholesale spot markets. Retail prices were not studied, since retail pricing often smoothes wholesale pricing, especially for smaller customers. For example, pricing of power to residential consumers is typically at a flat rate independent of time of use, since time of use is usually not recorded by meters in use by small consumers. Residential price levels are reset from time to time to ensure the cost of power is collected from consumers. However, larger consumers have the option of buying power in real time (paying real time pricing (RTP)); it is possible in the future that time of use metering will make this an option for all consumers.

The major software used in this research was MATLAB. In addition, the statistical software packages SAS and SPSS were used for a portion of data analysis. The power data set, which consists of over two million price and load data points, was managed by Microsoft Excel, which was used to produce some plots as well.

1.4 Arrangement of the Thesis

This thesis is paper-based, i.e., each of the three major chapters is a paper that has been prepared from the research work. During the course of the research, the database was expanded by the adding an extra year of data. In Chapters 2 and 3, the original papers that appeared in *Energy Policy* have been modified to incorporate the additional data, i.e., all of the results in this thesis are now based on a single expanded data set.

While the primary focus of this research is a detailed comparison of power prices in deregulated markets, a general overview of deregulation can be helpful to a researcher. Appendix A contains a general discussion of issues of deregulation, drawn from a literature survey for many markets.

At the start of the research a large database of hourly or half-hourly power price was gathered. Data sources are discussed briefly in each paper; Appendix B goes into greater detail on data cleaning, and provides an elementary analysis of the data sets, e.g. mean, standard deviation and skewness.

Chapter 2 is focused on comparing diurnal patterns in deregulated power markets, and identifies significant differences between these markets. In comparing diurnal patterns, normalized price data is used to allow patterns to be directly compared independent of the currency in which power is sold; Appendix C discusses issues of normalization of power prices in greater detail. A simple data filtration technique was initially used to test for the impact of outliers on the structure of price patterns, and is reported in Chapter 2. It indicated that some markets have diurnal patterns that are far more influenced by the power price on a small fraction of days than others. This led us to pursue the issue of volatility in greater detail.

Chapter 3 is a more detailed look at volatility in power price, focusing on short-term (hourly or half-hourly) price changes, and using the concept of price velocity, a measure that is related to how consumers view price changes. Again, significant differences are observed in deregulated markets in price velocity. Appendix D discusses the issue of volatility in greater detail, including a brief survey of other approaches to volatility.

Given the significant differences that are observed in price patterns and volatility between deregulated power markets, changes in time within a single market became a focus of interest. Chapter 4 looks at seasonal and annual changes in power price patterns and volatility, and again finds significant differences between markets. Appendix E develops the approach to seasonal analysis of data in greater detail.

Finally, Chapter 5 summarizes the research work and discusses the potential for future research work.

The belief held by the author at the onset of this research, and one that she still holds as it comes to completion, is that a number of technological, economic and political questions that will determine how electric power industry restructuring evolves are yet to be answered. It is not yet clear whether there will be an international convergence in the market structure under deregulation. One of the objectives of this research is to inspire further reserch that will ask the right questions and seek the right answers in identifying why different price patterns occur in deregulated markets. The author believes that this research will help to identify some of the intriguing questions.

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CHAPTER 2 DIURNAL PATTERNS OF POWER PRICES

To look at variations in power prices, diurnal patterns of power prices, in particular its daily average weekday and weekend patterns of changes are examined for 14 deregulated markets. The extent to which the diurnal pattern is determined by a small percentage of days of "price excursions" is examined by applying data filtration. The relationship between power price and load is investigated as well.

2.1 Introduction

Over the past decade many power markets have deregulated and moved to hourly or half-hourly adjustment of power price through a bidding process. In an effort to ensure a fair and open market, deregulated markets have usually started with a single mandated clearing pool through which all wholesale electric power is sold, giving a single price for the commodity at any point in time. The features of deregulated markets have been described by many (see, for example, Larsen and Bunn, 1999; Masson, 1999; Philipson and Willis, 1999; VanDoren, 1998). Specific arrangements vary from market to market, and are described elsewhere. (See, for example, Bower and Bunn, 2000, on England and Wales; Bushnell and Saravia, 2002, on New England; Johnsen, 2001, on Norway/Nord Pool; Mansur, 2001, on PJM; Puller, 2002, and Sioshansi, 2001, on California; Wolak, 1999, on England and Wales, Nord Pool, Victoria (Australia), and the north and south islands of New Zealand; and Wolak and Patrick, 1997, on England and Wales. In addition, there are specific web sites for the markets included in this study, listed in Table 2.6.)

It should be noted that a single price for power does not imply that all customers in effect pay that price: in deregulated markets, hedging arrangements are often made in parallel to purchases from the central clearing pool. In effect, a generator and a distributor or consumer settle the difference between an agreed price and the pool price by periodic remittance.

Electrical power is not practically storable[1]; it is not transported over oceans except for short distances to islands, and has a significant cost for long distance transport over land. As a result, the price of power in one deregulated market can change independent of the price of power in another distant deregulated market. The price of electrical power in California, for example, has no direct relation to the price of power in New Zealand or England, and almost no relation to the price of power in the eastern United States. Each of these markets may have similar fuel sources for the generation of power, and similar diurnal usage patterns that stem from common social patterns, for example, sleeping in the evening or working a five-day workweek. However, many specific factors affecting supply and demand operate independently in these markets.

This stands in contrast to oil: because it is easily and cheaply transportable by ship and pipeline, oil prices in different areas of the world vary only by quality and transportation differentials. Natural gas is more expensive to transport by pipeline or as liquefied natural gas (LNG), and capital facilities take a long time to construct, but over time these transportation options again drive a world price adjusted for transportation differentials.

The fact that electricity is not storable also leads to high hourly variations in price in deregulated markets. Unlike other commodities, it is not unusual for electrical power to show both a significant daily variation in price and large variations in average price between days. Figure 2-1 shows the maximum and minimum daily power price in Alberta, Britain, Scandinavia, and New Zealand, represented by the top and bottom of the bar for each day. (The same information of the other markets is shown in Section 2.8.2. Note that the gap in the power prices for Britain is due to missing price data in January and February 1998.) The high intraday and inter-day variability in power price is evident.

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[1] Hydropower can be deferred provided that alternate generation and reservoir capacity is available, offering short term equivalent "storage". Pumped storage (filling an elevated reservoir in periods of low demand and regenerating the power during periods of high demand) exists in some jurisdictions, but is expensive and negligible in quantity compared to daily use. Hence electrical power is not practically storable in significant quantities.

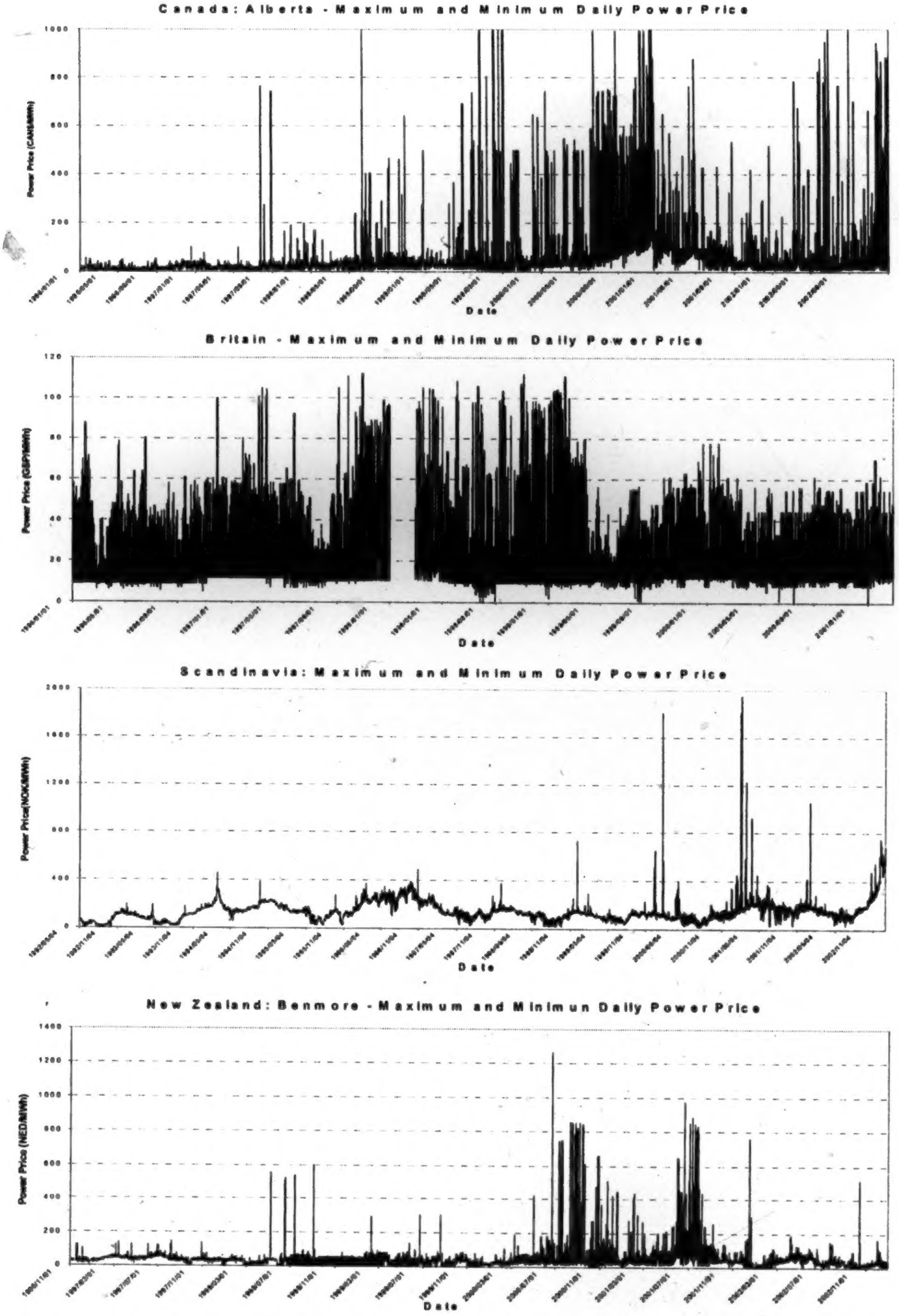

Figure 2-1 Maximum and Minimum Daily Power Prices in Four Selected Markets.

For these reasons, power price in deregulated markets provides a unique opportunity to study inter-market variations in the price of a basic commodity. In this chapter, variations in the pattern of intraday (diurnal) price are explored for many deregulated power markets.

Wolak (1999) compared annual average power prices in five markets, and looked at a normalized daily, weekly, monthly, and annual volatility, using the measure of highest price minus the lowest price in the period divided by the average price of that period. Wolak and Patrick (1997) looked in detail at power price in Britain, including an analysis of power price as a function of load. Knittel and Roberts (2001) looked at daily, weekly, and seasonal patterns in the California market; they noted that existing financial models of price could not capture the erratic nature of electricity prices.

In this chapter the author focuses on the perspective of the customer: what sense can a power consumer make of daily power price patterns, and can the consumer make intelligent decisions about future actions based on the information contained in those patterns. The focus is not on the absolute level of power price, but rather on how its variations are shaped by and in turn shape human behavior. The author examines electrical power price, and in particular its daily weekday vs. weekend pattern of change, for a large number of deregulated markets. The author also explores the extent to which this pattern is determined by a small percentage of days of "price excursion", by applying simple data filtration. The author compares diurnal price to load. The author finds that some deregulated power markets are more comprehensible to a power consumer than others. The ability to face an open market and shape power consumption based on expected price patterns is not uniform between markets.

2.2 Electrical Power Price Data

Table 2-1 shows the details of power price data collected for this study. One notable region not represented in this study is Latin America; repeated efforts to obtain hourly price data were unsuccessful. Errors in data sets as received consisted of missing data, questionable data, and duplicate data, i.e., multiple

Table 2-1 Power Price Data for Deregulated Markets

Market	Short Name	Frequency	Duration	Number of Days Studied	Number of Data Points	Number of Data Cleaned	Percent of Data Cleaned (%)
Canada: Alberta	**PPOA**	hourly	1996/01/01~2002/12/31	2,557	61,368	14	0.02
USA: Southern California	**Scal**	hourly	1998/04/01~2001/01/31	1,037	24,888	198	0.80
USA: Northern California	**Ncal**	hourly	1998/04/01~2001/01/31	1,037	24,888	181	0.73
USA: PJM	**PJM**	hourly	1997/04/01~2002/12/31	2,101	50,424	361	0.72
USA: New England	**NEPool**	hourly	1999/05/01/~2002/12/31	1,341	32,184	338	1.05
Germany: Leipzig	**LPX**	hourly	2000/06/16~2002/12/31	929	22,296	19	0.09
Netherlands	**APX**	hourly	1999/05/26~2002/12/31	1,316	31,584	78	0.25
Britain	**UK**	half hourly	1996/01/01~1997/12/31, 1998/03/01~2001/2/28	1,827	87,696	72	0.08
Spain	**OMEL**	hourly	1998/01/01~2002/12/31	1,826	43,824	9	0.02
Scandinavia	**Nord Pool**	hourly	1992/05/04~2002/12/31	3,894	93,456	10	0.01
Australia: South Australia	**NEMSA**	half hourly	1998/12/13~2002/12/31	1,480	71,040	14	0.02
Australia: Snowy	**NEMSNOWY**	half hourly	1998/12/13~2002/12/31	1,480	71,040	20	0.03
Australia: New South Wales	**NEMNSW**	half hourly	1998/12/13~2002/12/31	1,480	71,040	20	0.03
Australia: Queensland	**NEMQLD**	half hourly	1998/12/13~2002/12/31	1,480	71,040	22	0.03
Australia: Victoria	**NEMVIC**	half hourly	1998/12/13~2002/12/31	1,480	71,040	23	0.03
New Zealand: Benmore	**NZEMBEN**	half hourly	1996/11/01~2002/12/31	2,252	108,096	457	0.42
New Zealand: Haywards	**NZEMHAY**	half hourly	1996/11/01~2002/12/31	2,252	108,096	407	0.38%
New Zealand: Otahuhu	**NZEMOTA**	half hourly	1996/11/01~2002/12/31	2,252	108,096	407	0.38
				Total:	1,152,096	2,650	0.23

data points for a single time period. Missing data were filled in and questionable data were replaced by linear interpolation; duplicate data points were consolidated by averaging. (Data cleaning methods are described in Appendix B.) As noted in Table 2-1, all of the data sets had error rates (percent of data cleaned) less than 1.1%, and all but four (i.e., the data sets of Southern and Northern California, PJM, and New England) were 0.5% or less; so that the impact of data error is negligible and data clean up methodology is not a significant source of error in the results.

When deregulated markets are close and connected by transmission, power prices tend to equalize. The author obtained data from 18 markets, but eliminated four because the correlation with one or more markets in this study exceeded 0.8 (a full table of cross correlations for the 18 markets is shown in Section 2.8.3). Tables 2-2 shows a summary of the cross correlations. Note that a low correlation between independent power markets can be expected based on

Table 2-2 Cross Correlation in Power Prices Between Markets

Markets	**Strong Correlation ($R>0.8$)**	**Medium Correlation ($0.4 \le R \le 0.6$)**
1: Canada: Alberta	None	USA: South and North California
2: USA: Northern California	USA: Southern California	Canada: Alberta
3: USA: PJM	None	None
4: USA: New England	None	None
5: Germany: Leipzig Exchange	None	Netherlands and British
6: Netherlands	None	Germany
7: Britain	None	Germany
8: Spain	None	None
9: Scandinavia	None	None
10: Australia: South Australia	None	Australia: Snowy and Victoria
11: Australia: New South Wales	Australia: Snowy	Australia: Victoria
12: Australia: Queensland	None	None
13: Australia: Victoria	None	Australia: South Australia, Snowy and New South Wales
14: New Zealand: Benmore	New Zealand: Haywards and Otahuhu	None

Note: No correlation was found between 0.6 and 0.8; all correlations other than those noted in the table are below 0.4; and R stands of correlation coefficient.

common human patterns of power usage: as noted above, people around the world tend to sleep between midnight and 6 A.M., and the five day work week is common in industrial societies.

Deregulation is often phased into markets that have historically been regulated, and during transitional periods markets are buffered by holdover arrangements. For example, the Province of Alberta established a central power pool through which all power was marketed as early as 1996, but major utilities had legislated arrangements in place (effectively legislated hedges) that served in effect as ongoing regulatory mechanisms until January 1, 2000. PJM, which mainly includes Pennsylvania, New Jersey, Delaware and Maryland in the eastern U.S., had cost based bidding until April 1999, when full deregulation of bidding occurred. Similarly, the Leipzig Exchange (LPX) in Germany has been involved in wholesale power trading since June 2000, but much of the power in Germany has been marketed through regulated channels. The extent to which power price in these transitional periods reflects a fully deregulated market is uncertain and we can expect over time that some changes in price patterns may emerge as some markets move to fuller deregulation while other markets move to partial re-regulation.

2.3 Diurnal Patterns of Power Price

All power markets investigated show a distinct daily variation in the price of electrical power. However, the pattern of variation varies between markets.

Figure 2-2 shows the normalized diurnal average power price for each market. Average power price for each time period is normalized against the weekday average price (WDAP) for weekday data, and weekend average price (WEAP) for weekend data; hence in Figure 2-2 each of the two curves is normalized to unity. (Note that three data points are truncated in the plots of New South Wales and Queensland, respectively, and one datum point is truncated in the plot of Victoria. Figure 2-3 shows the same curves where the average power price for each time period is normalized against the overall average price (OAP) in each market. Also note that three data points are truncated in the plots of New South Wales and Queensland, respectively.) One minor source of error is that

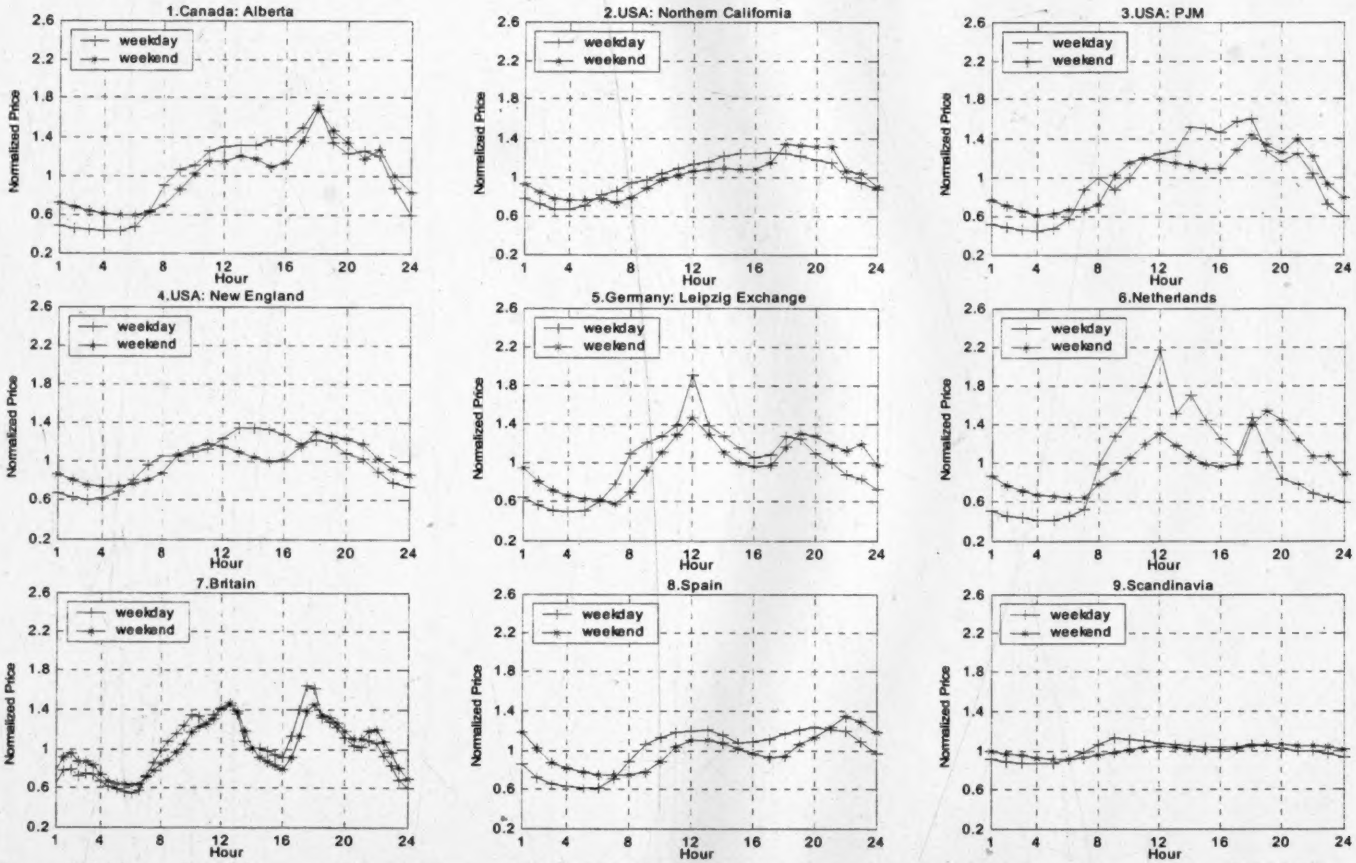

Figure 2-2 Normalized Average Diurnal Power Prices (Weekday Values Normalized to Weekday Average Price (WDAP) and Weekend Values Normalized to Weekend Average Price (WEAP)).

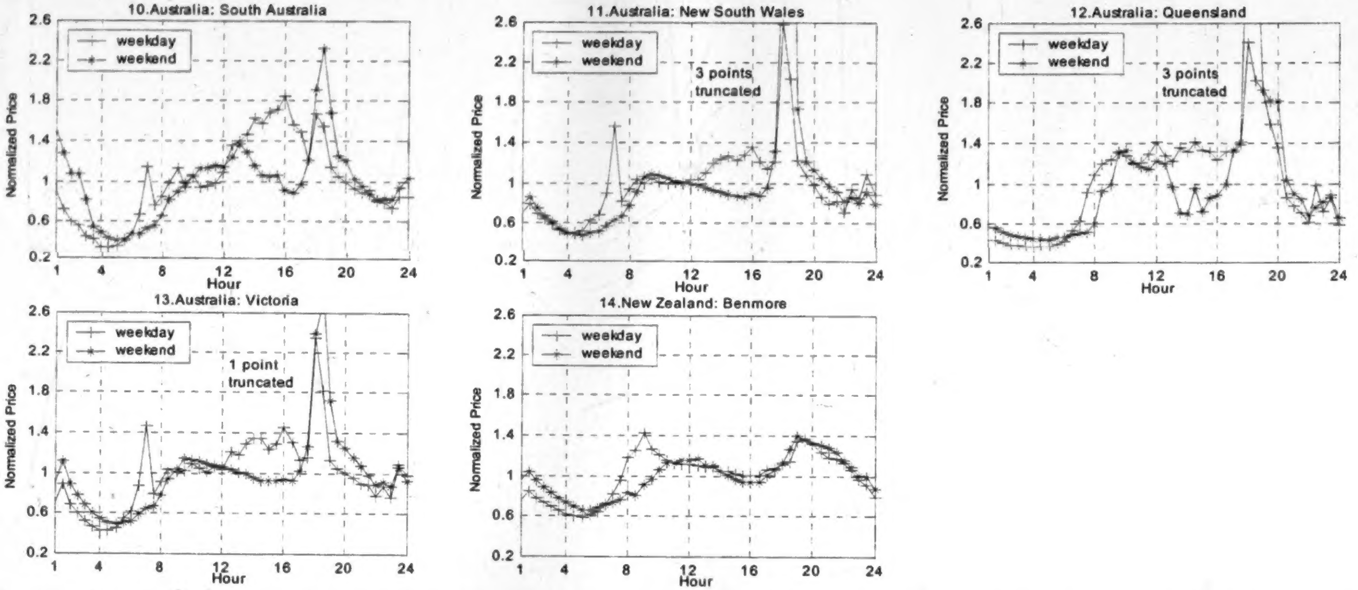

Figure 2-2 Normalized Average Diurnal Power Prices (Weekday Values Normalized to Weekday Average Price (WDAP) and Weekend Values Normalized to Weekend Average Price (WEAP)) (Continued).

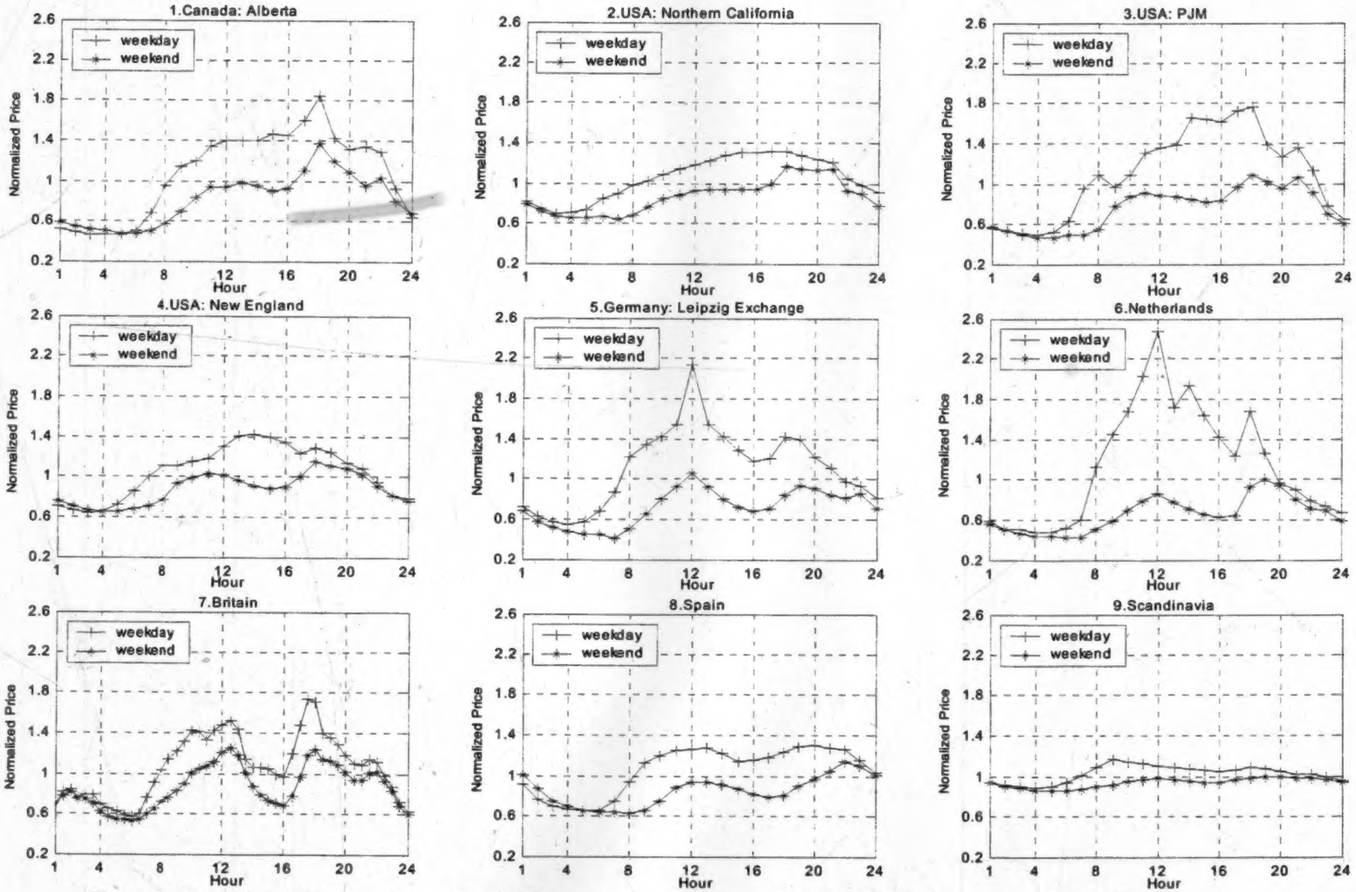

Figure 2-3 Normalized Average Diurnal Power Prices (Normalized to Overall Average Price (OAP)).

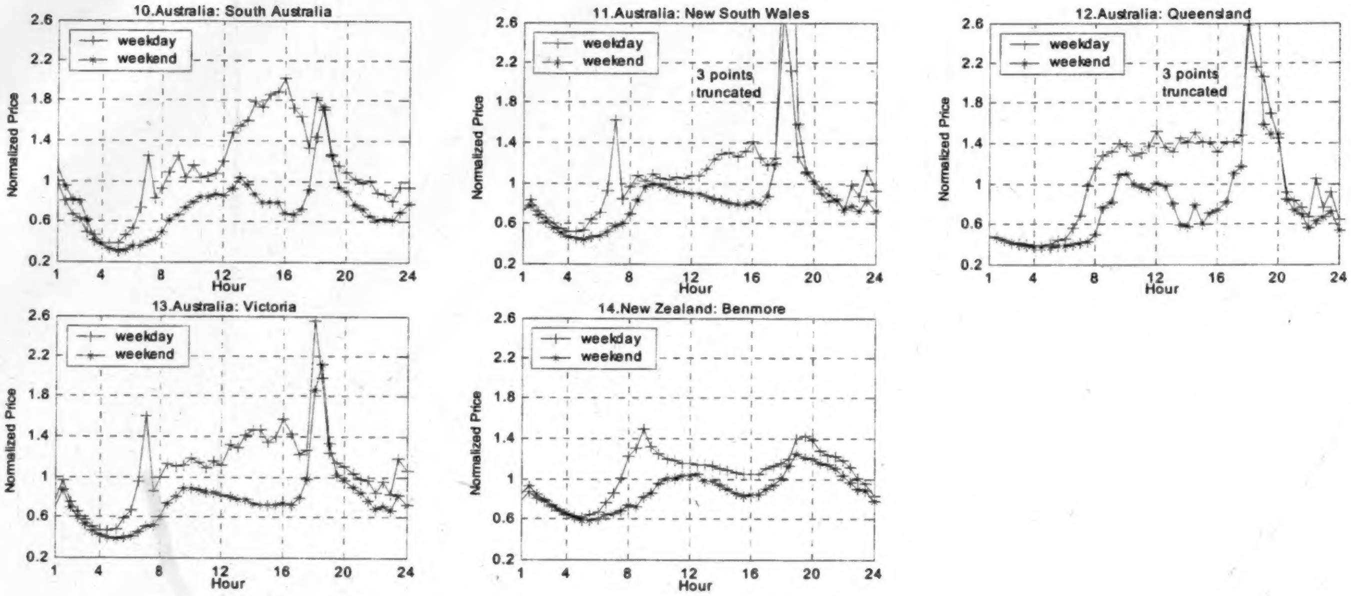

Figure 2-3 First Type Normalized Average Diurnal Power Prices (Normalized to Overall Average Price (OAP)) (Continued).

statutory holidays that fall during the week are not identified and grouped with weekend days. For each market, the overall average price, weekday average price, weekend average price, the ratio of maximum to minimum price for weekday and weekend (WDR and WER, respectively); and the ratio of weekday average to weekend average price (WD/WEAPR) are computed and shown in Table 2-3 and Figure 2-4. Note that price data is in local currency per MWh (see Section 2.8.1 for the specific currency for each market). For three markets a truncated range of data was used that aligns with the onset of fuller deregulation in that market: Alberta (00/01/01~01/12/31), PJM (99/04/01~01/12/31), and Scandinavia (96/01/01~01/12/31).

Table 2-3 Daily Average Power Prices

		Average Price (Local Currency/MWh)		
Market	**Duration**	**Overall (OAP)**	**Weekday (WDAP)**	**Weekend (WEAP)**
1. Canada: Alberta	2000/01/01~2002/12/31	82.86	88.99	67.59
2. USA: Northern California	1998/04/01~2001/01/31	62.41	65.71	54.14
3. USA: PJM	1999/04/01~2002/12/31	30.19	33.15	22.81
4. USA: New England	1999/05/01/~2002/12/31	38.30	40.18	33.61
5. Germany: Leipzig Exchange	2000/06/16~2002/12/31	22.34	24.87	16.02
6. Netherlands	1999/05/26~2001/12/31	34.92	39.74	22.85
7. Britain	1996/01/01~1997/12/31, 1998/03/01~2001/2/28	21.14	22.37	18.08
8. Spain	1998/01/01~2002/12/31	37.30	39.55	31.67
9. Scandinavia	1996/01/01/~2002/12/31	158.31	162.37	148.15
10. Australia: South Australia	1998/12/13~2002/12/31	47.01	51.70	35.27
11. Australia: New South Wales	1998/12/13~2002/12/31	32.67	33.86	29.69
12. Australia: Queensland	1998/12/13~2002/12/31	43.58	46.64	35.91
13. Australia: Victoria	1998/12/13~2002/12/31	32.34	35.23	25.10
14. New Zealand: Benmore	1996/11/01~2002/12/31	42.57	44.40	38.01

Several observations emerge from an inspection of Figures 2-2, 2-3 and 2-4; and Table 2-3:

- All markets show markedly lower prices in the early morning hours (midnight to 6 A.M.) than in all other time periods, a reflection that humans reduce their personal and work consumption of power while sleeping. For

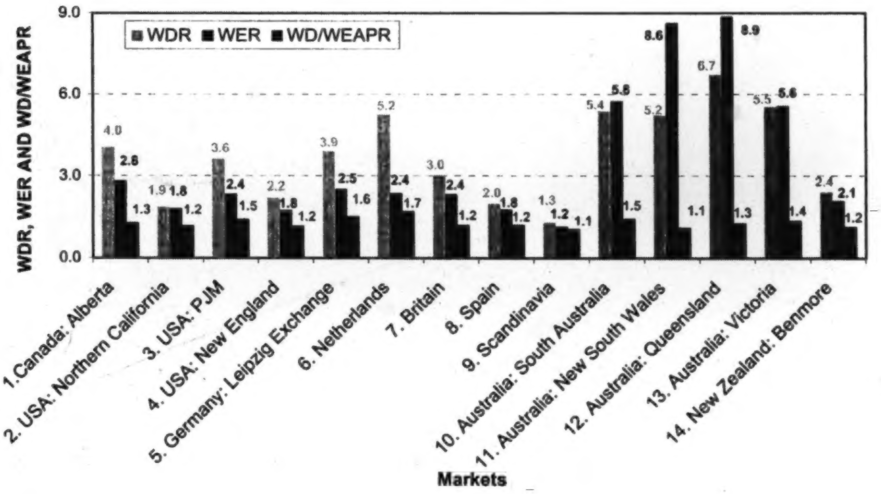

Figure 2-4 Average Maximum vs. Minimum Price Ratios on Weekdays and Weekends (WDRs and WERs), and Weekday to Weekend Average Price Ratios (WD/WEAPRs).

consumers facing RTP, shifting elective weekday power usage to early morning would result in savings in all markets.

- The early morning actual power prices are very close on weekdays and weekends (the gap in Figure 2-2 is an effect of normalization). The lower weekend overall price arises from lower prices in daytime and evening, but not from 1 to 6 A.M.

- All markets show a higher daily overall average price for weekdays vs. weekends. This likely reflects lower power usage resulting from a common pattern of work in industrial societies: office, administrative and educational work tends to occur during weekdays. Shifting elective weekday power usage to the weekend would result in savings in all markets.

- There is a dramatic difference in markets in the range between the daily average minimum and maximum price, especially on weekdays. Note, for example, that the Netherlands shows a value of 5.2 for the average weekday maximum to minimum price (and the four markets in Australia all show the value of the same ratio over 5.0), while the same value in

Northern California is 1.9 and in Scandinavia is 1.3. Thus there is a significantly different driving force for shaping daily power consumption from market to market; on weekdays a consumer in the Netherlands or Australia would, in theory, have a far higher incentive for avoiding mid-day power usage compared to consumers in other markets.

One likely cause of the wide variation in daily average maximum to minimum price is the generation mix in a specific market; Scandinavia, for example, is characterized by very large hydro and wind resources, which provided about 54% of total generating capacity in 2000 (Flatabø *et al.*, 2003), while the Netherlands is relying on natural gas for peaking (http://www.apx.nl). In Australia, the power generation is mixed with various sources and is different in each region (Moran, 2002; Beder, 2003; Phunnarungsi and Dixon, 2003)

- There is also a difference in markets in the ratio of average weekday to weekend power price. Note, for example, that in Scandinavia the value of this ratio is 1.1, the Netherlands it is 1.7, and in Leipzig the reported data show the ratio of 1.6. Thus there is a significantly different driving force for moving elective power consumption from weekdays to weekends.

- Deregulated power price shows different diurnal patterns: single peak, double peak, and choppy.

North American markets display a monotonic, or near monotonic, increase in weekday power price from a daily minimum in the early morning to a daily maximum in the late afternoon/early evening. The author refers to these markets as "single peak" markets. This is in marked contrast to most markets in Europe, plus New Zealand, which show a distinct two maxima pattern. The author refers to these markets as "double peak" markets. Note that in some markets the first peak occurs at noon (e.g. in Leipzig, the Netherlands, Britain and Spain, while it occurs at 9 A.M. in New Zealand and Scandinavia.

These two different patterns may reflect a different technology of space heating. The author speculates that European price patterns may reflect more use of electrical based space heating at home, workplace and retail settings, perhaps coupled with a tendency to lower indoor temperatures to a greater extent during the night. However, this is a speculation, and the underlying reasons for the variation in diurnal price pattern is a subject for future research.

Australian markets show a choppy pattern of many peaks. Two markets in Australia (New South Wales and Victoria) show a high spike at 7 A.M. on weekdays or at 9 A.M. on weekends. A late afternoon super peak between 6 P.M. and 7 P.M. occurs in all four markets. Again, these patterns of price are a subject for future research.

- Several North American markets (see, for example, PJM and New England) show a double peak pattern on weekends, suggesting a different fundamental pattern of power usage as compared to weekdays.
- Weekday and weekend normalized power prices, as shown in Figure 2-2, show remarkable similarities in pattern in some markets (see, for example, Alberta, Britain and New Zealand). Although the magnitude of weekend power price is lower in these markets, the relative diurnal variation is virtually identical. However, in other markets the impact of weekend usage is to reduce a high mid-day peak (see, for example, Netherlands and South Australia).

2.4 Filtering Data: Removing the Impact of Price Extremes

Some deregulated markets have gone through periods of high prices, California being the most frequently cited example. In this study the author has used data filtration to assess the impact of periods of unusually high or low price by plotting diurnal patterns of average prices with selective days omitted.

Two levels of filtering, 10% and 20%, were chosen to remove part of the data. For 10% filtration the author identified the 5% of days in the data set on which the lowest price occurred and the 5% of days on which the highest price occurred, and removed all 24 or 48 price data points associated with each of those days from the data set. For 20%, the same approach was used removing the days with the highest and lowest 10% of prices. The diurnal price patterns were then recalculated for the filtered data sets. The filtration levels are arbitrary and used as a coarse screen of the impact of price excursions (outliers) on overall price patterns.

Figure 2-5 shows six plots for one market, Northern California, illustrating the full effect of filtration for one market. (The same plots for other markets are shown in Section 2.8.4.) Filtering the data reduces the absolute value of the average price, but, remarkably, the diurnal pattern, especially on weekdays, is virtually unchanged. This means that a customer in California can expect a fairly predictable daily variation in price regardless of the overall average price level.

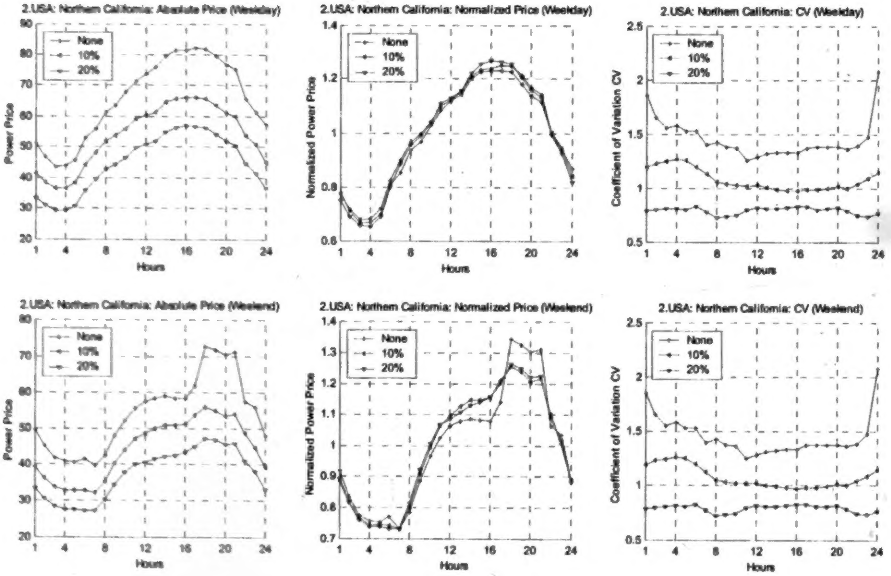

Figure 2-5 Effect of Data Filtration: Northern California.

This constancy in normalized price patterns is not true for most markets. Figure 2-6 shows the normalized weekday average diurnal power price for each of the 14 markets, at three levels of filtration: none, 10%, and 20%. (The same data for weekends is in Section 2.8.4). It can be seen that high peaks of average price are significantly reduced by filtration in several of these markets: see, for example, PJM and NEPOOL in North America; Germany and Scandinavia in Europe; all markets in Australia, and New Zealand. Table 2-4 shows the impact

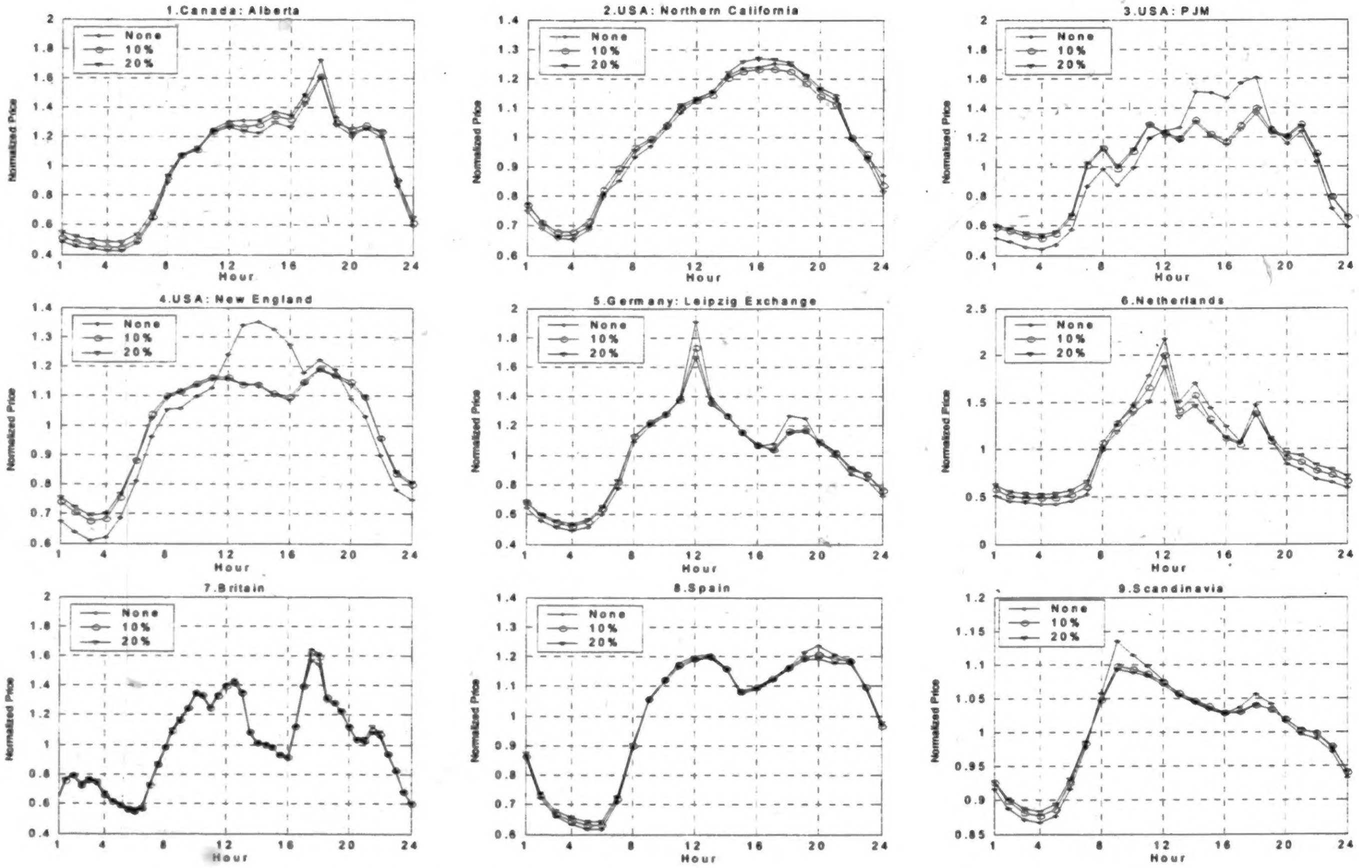

Figure 2-6 Effect of Data Filtration on Normalized Weekday Diurnal Pattern Power Prices.

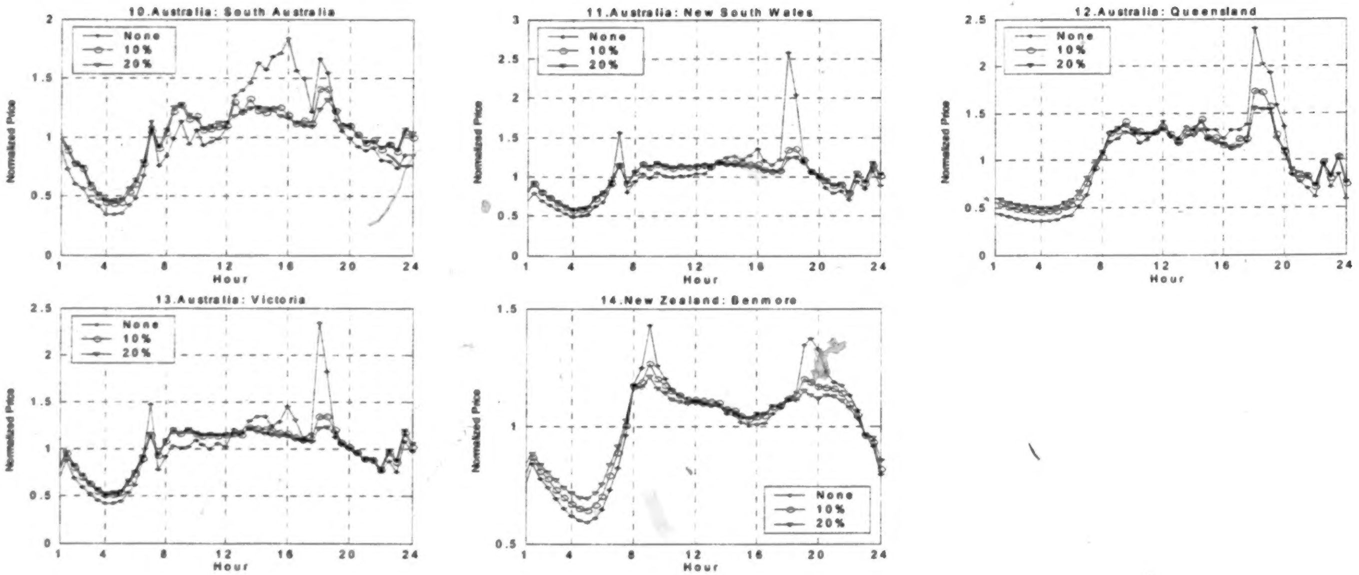

Figure 2-6 Effect of Data Filtration on Normalized Weekday Diurnal Pattern Power Prices (Continued).

of filtration maximum to minimum price ratio, WDR, for all markets. Section 2.8.4 contains the same information for weekends and overall prices. of data on the weekday average price, WDAP, and the weekday maximum to minimum price ratio, WDR, for all markets. Section 2.8.4 contains the same information for weekends and overall prices.

Table 2-4 Effect of Data Filtration on Weekday Prices

							Impact of Data Filtration			
	Average Weekday Price (WDAP)			Max/Min Ratio (WDR)			% Change of WDAP		% Change of WDR	
Market	**None**	**10%**	**20%**	**None**	**10%**	**20%**	**10%**	**20%**	**10%**	**20%**
1. Canada: Alberta	89.0	83.8	77.3	4.04	3.59	3.33	5.84	13.13	11.12	17.59
2. USA: Northern California	65.7	53.7	44.8	1.88	1.81	1.95	18.32	31.85	3.74	-3.24
3. USA: PJM	33.1	28.8	28.2	3.63	2.71	2.55	13.03	14.97	25.24	29.69
4. USA: New England	40.2	36.6	35.9	2.21	1.77	1.71	9.00	10.52	19.98	22.58
5. Germany: Leipzig Exchange	24.9	23.8	23.6	3.90	3.31	3.10	4.41	5.09	15.15	20.34
6. Netherlands	39.7	35.1	32.5	5.24	4.15	3.55	11.56	18.29	20.80	32.17
7. Britain	22.4	22.1	21.8	3.03	2.94	2.79	1.05	2.70	2.99	7.80
8. Spain	4.0	3.9	3.9	2.01	1.92	1.86	1.50	1.81	4.51	7.26
9. Scandinavia	162.4	156.7	154.0	1.31	1.25	1.24	3.50	5.16	4.38	5.50
10. Australia: South Australia	51.7	40.6	39.1	5.38	3.22	2.86	21.42	24.29	40.14	46.83
11. Australia: New South Wales	33.9	29.5	28.8	5.22	2.35	2.10	12.88	15.06	54.98	59.86
12. Australia: Queensland	46.6	37.1	34.1	6.72	3.83	3.13	20.51	26.95	43.07	53.48
13. Australia: Victoria	35.2	29.2	28.3	5.54	2.64	2.33	17.09	19.67	52.40	57.98
14. New Zealand: Benmore	44.4	41.0	38.7	2.42	1.97	1.75	7.65	12.75	18.60	27.66

Note: Units for price are local currency unit per MWh in all markets except Spain where the unit for price is Euro cent per KWh.

Data filtration again illustrates that from the perspective of the customer, deregulated markets are not identical. A customer in Britain or Scandinavia can see a relatively stable price and stable diurnal pattern, and hence can make decisions about power purchase and diurnal manipulation of consumption (for example, by scheduling factory activities that have high power consumption to periods of low power price) with some confidence. A customer in the Netherlands or Australia does not have that confidence in market stability:

removing 20% of the days from the data set in South Australia, for instance, drops average power price by almost 24%, and shifts the diurnal maximum to minimum ratio from over 5.4 to 2.9. A consumer accepting RTP who is trying to make a rational response to the market in South Australia is going to face a far bigger challenge than the same industry in Britain, and will have a far larger incentive to lay off the market variability through a hedging mechanism because so much of the diurnal variance arises from a small subset of days. There are thus differences between markets in the likelihood of DSM of power prices.

2.5 Diurnal Prices vs. Diurnal Load, and Diurnal Prices vs. Excess Generation Capacity

Figure 2-7 shows the normalized hour or half-hour average price for weekdays, and the corresponding normalized average total market load (i.e., usage or demand for power) for 13 of the 14 markets for which total power demand data is available. Note that one datum point was truncated in the plot for New South Wales. (Comparable plots for weekend power price and load are shown in Section 2.8.5. Both the price and load data are normalized relative to the weekday average values on weekdays and weekend average values on weekends.) The load data, as shown in Table 2-5, was "cleaned" in a manner similar to the procedure for price data. Again, the ratio of cleaned load data is less than 1.1% in all markets, and less than 0.5% in all but two markets (Northern California and New England). The total number of power load data points is over a half million. Note that the load data for Scandinavia is available from 1997, thus the price data used to calculate the correlation between price and load in this market is, accordingly, from 1997 as well. Also note that load data is not available in New Zealand. Figure 2-8 shows the plots of hour or half-hour price against load, and Figure 2-9 shows the correlation between hour or half-hour price and load.

Several observations emerge from an inspection of Figures 2-7, 2-8 and 2-9; and Table 2-5:

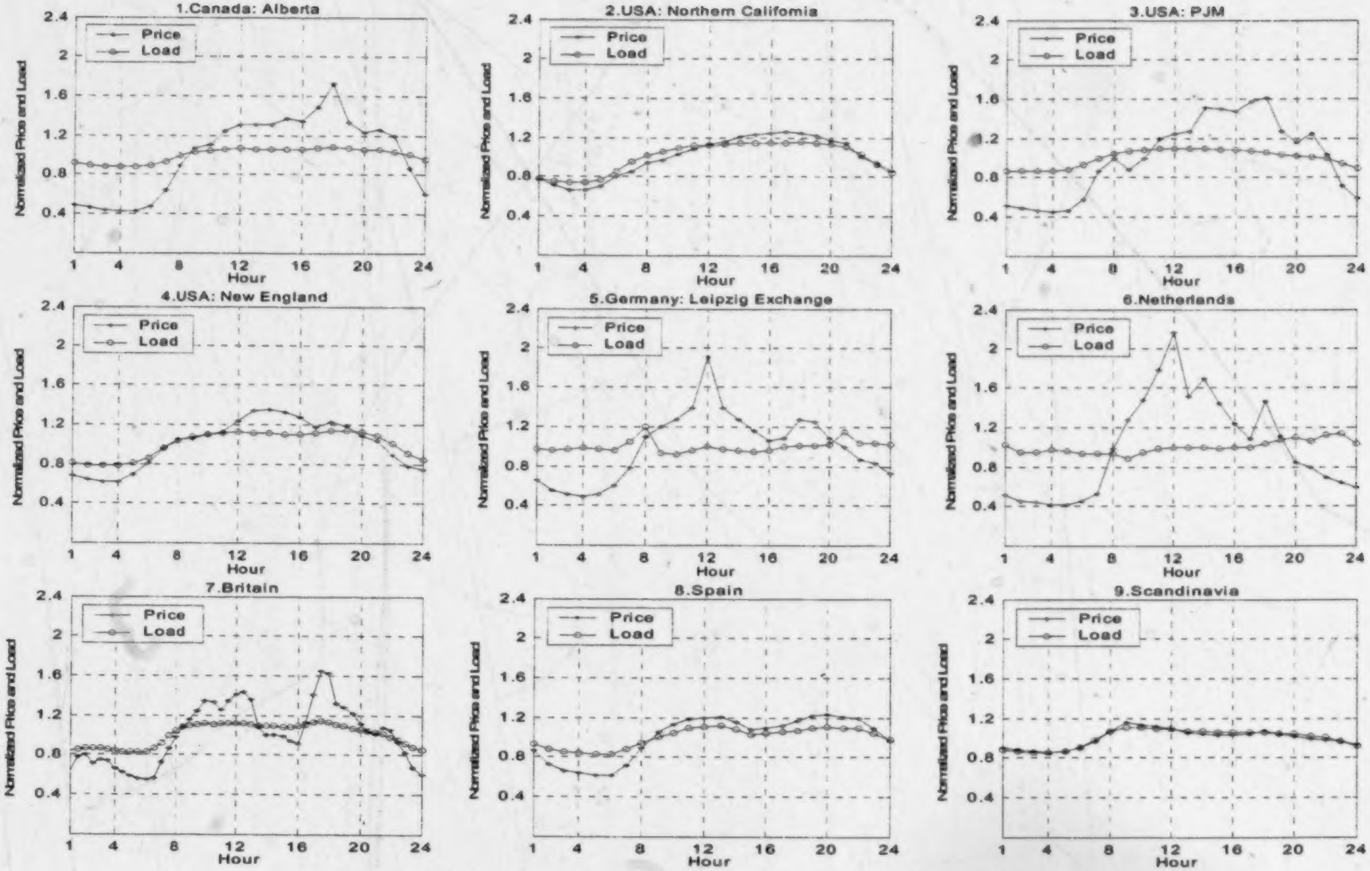

Figure 2-7 Normalized Average Weekday Power Prices and Load.

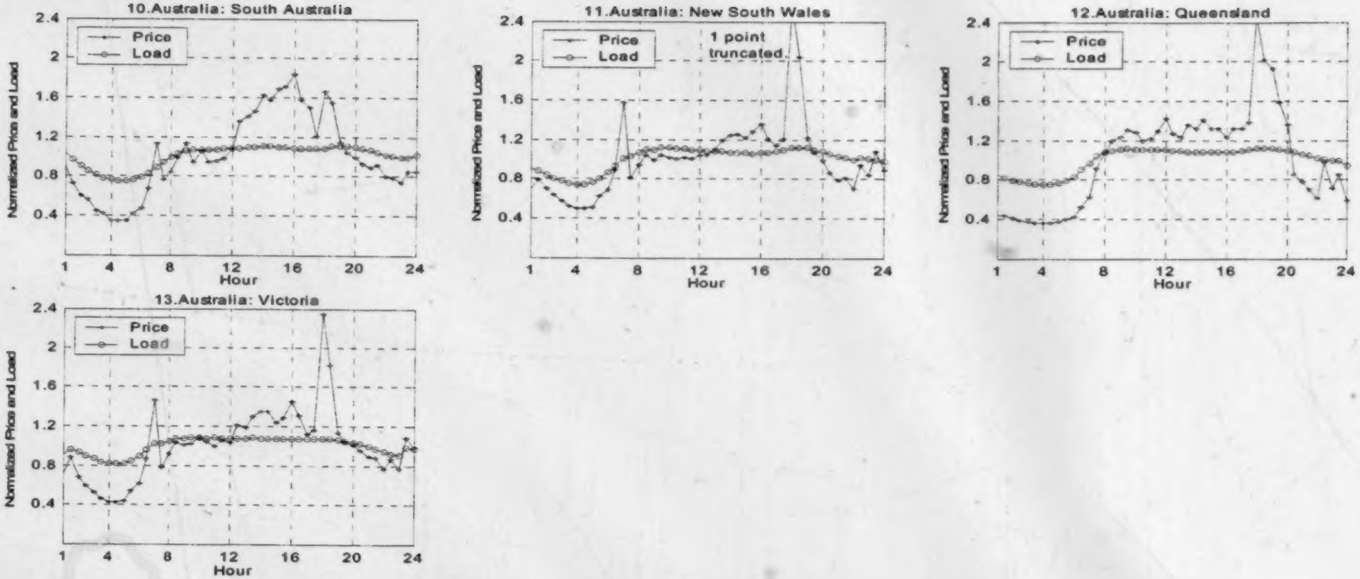

Figure 2-7 Normalized Average Weekday Power Prices and Load (Continued).

Table 2-5 Load Data for Deregulated Markets

Market	Duration	Number of Data Points	% of Data Cleaned (%)	Overall		Weekday		Weekend		Ratio of Average Weekday to Average Weekend Load
				Average Load (OAL)	Max/Min Ratio (R)	Average Load (WDAL)	Max/Min Ratio (WDRL)	Average Load (WEAL)	Max/Min Ratio (WERL)	(WD/WEALR)
1. Canada: Alberta	2000/01/01~2002/12/31	26,304	0.03	6,385	1.21	6,479	1.23	6,149	1.17	1.05
2. USA: Northern California	1998/04/01~2001/01/31	24,888	0.73	26,286	1.54	27,197	1.57	24,006	1.46	1.13
3. USA: PJM	1999/04/01~2002/12/31	32,904	0.02	31,033	1.27	31,372	1.27	30,185	1.27	1.04
4. USA: New England	1999/05/01/~2002/12/31	32,184	1.05	14,746	1.43	15,290	1.46	13,391	1.35	1.14
5. Germany: Leipzig Exchange	2000/06/16~2002/12/31	22,296	0.09	1,839	1.25	1,910	1.30	1,660	1.16	1.15
6. Netherlands	1999/05/26~2002/12/31	31,584	0.25	893	1.25	911	1.29	848	1.15	1.07
7. Britain	1996/01/01~1997/12/31, 1998/03/01~2001/2/28	87,696	0.08	16,506	1.35	17,276	1.39	14,569	1.26	1.19
8. Spain	1998/01/01~2002/12/31	43,824	0.02	19,876	1.30	20,723	1.34	17,758	1.29	1.17
9. Scandinavia	1997/01/01/~2002/12/31	52,584	0.00	9,190	1.24	9,390	1.28	8,692	1.16	1.08
10. Australia: South Australia	1998/12/13~2002/12/31	71,040	0.03	1,443	1.46	1,500	1.47	1,301	1.44	1.15
11. Australia: New South Wales	1998/12/13~2002/12/31	71,040	0.03	7,873	1.49	8,135	1.51	7,218	1.45	1.13
12. Australia: Queensland	1998/12/13~2002/12/31	71,040	0.04	4,896	1.48	5,045	1.49	4,525	1.44	1.11
13. Australia: Victoria	1998/12/13~2002/12/31	71,040	0.03	5,225	1.29	5,415	1.33	4,752	1.24	1.14
14. New Zealand: Benmore	No load data available.									
Total number of data points: 638,424.										

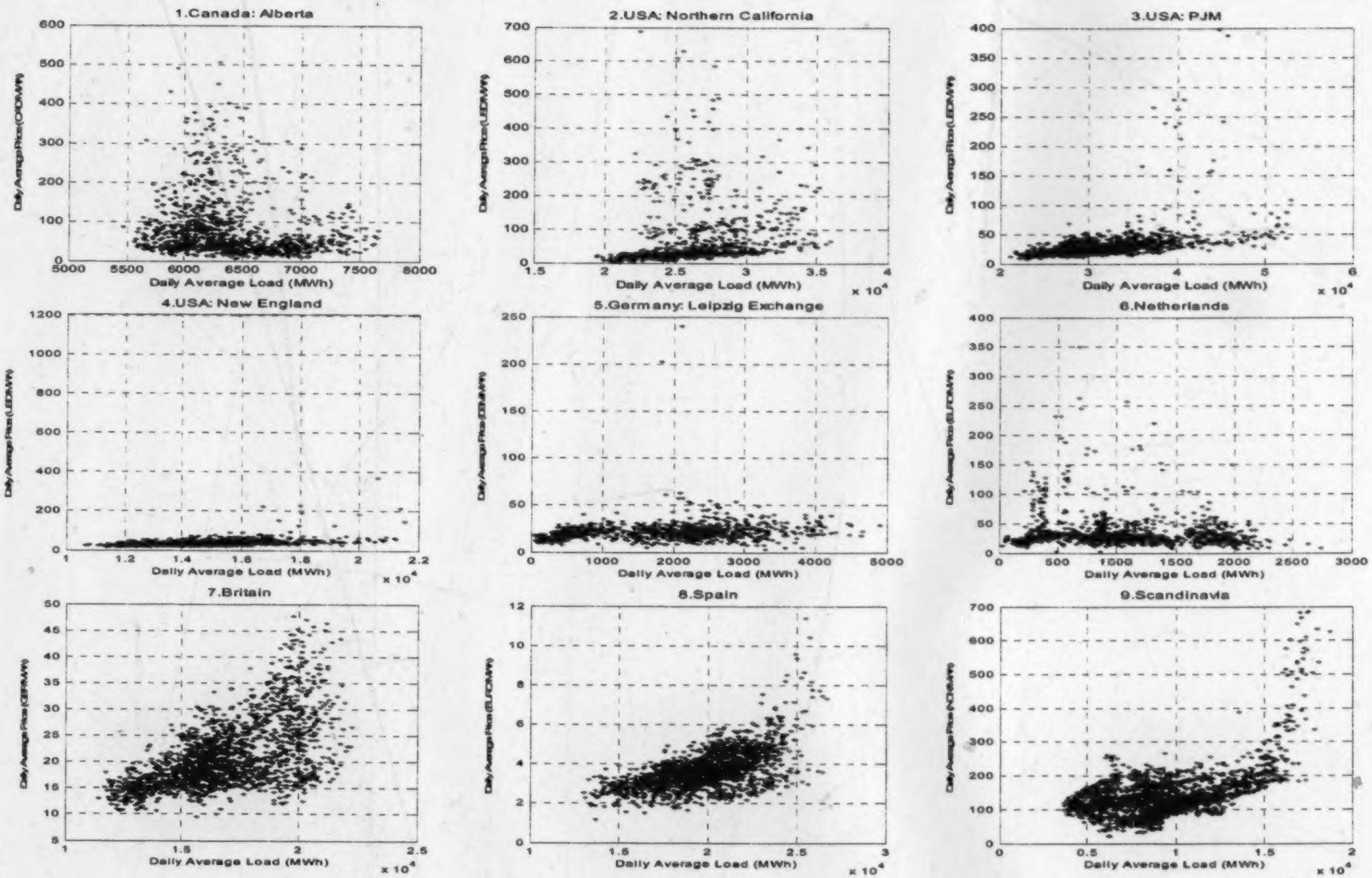

Figure 2-8 Power Prices vs. Load.

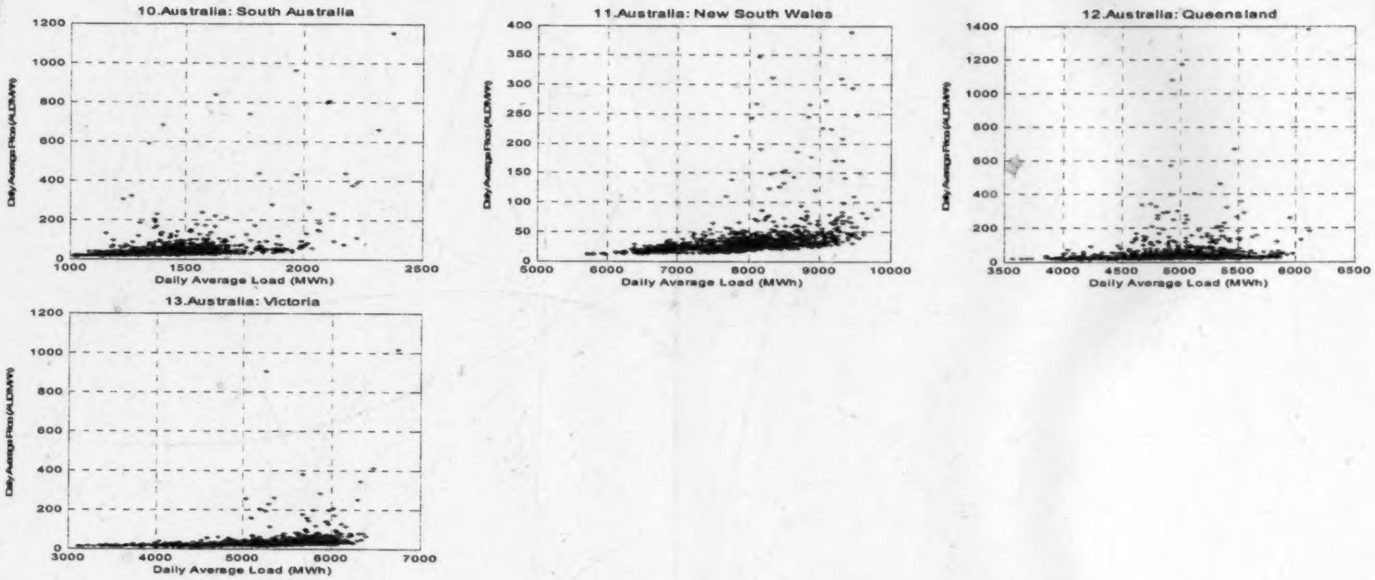

Figure 2-8 Power Prices vs. Load (Continued).

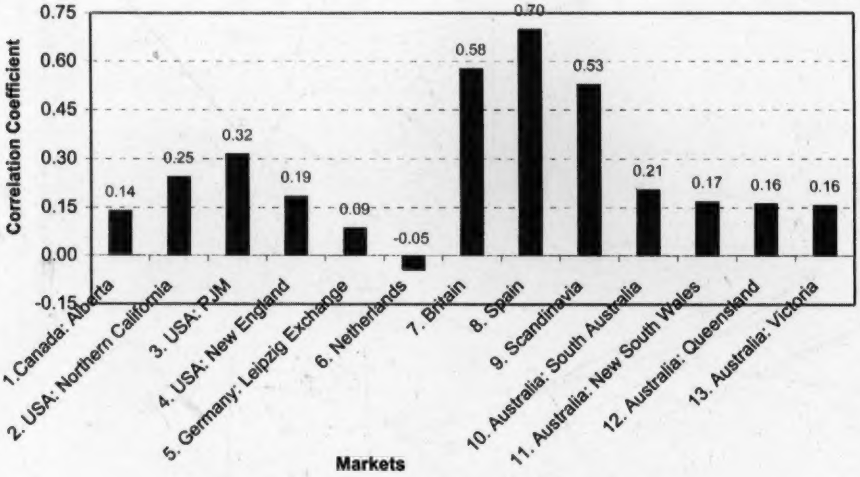

Figure 2-9 Correlation between Power Prices and Load.

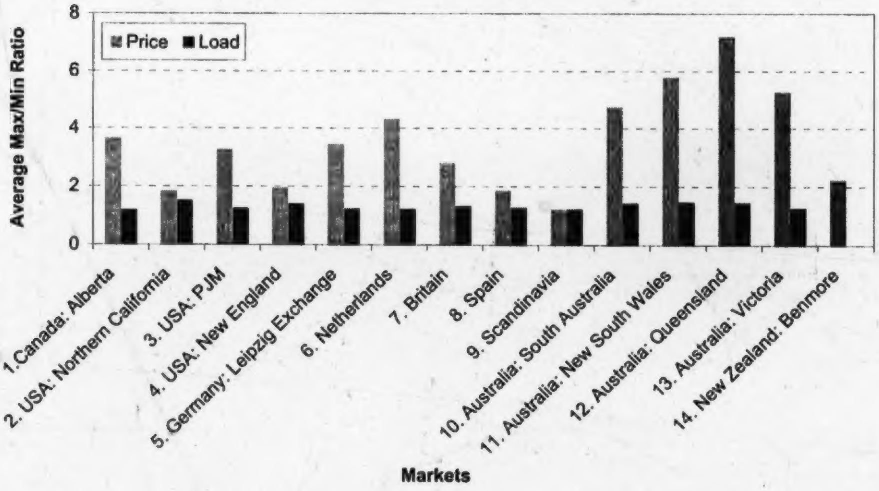

Figure 2-10 Ratios of Maximum to Minimum of Power Prices and Load.

- Diurnal average price changes reflect average load changes, but are far more exaggerated, i.e., a small change in average normalized load creates a larger change in average normalized price. This is also clear from comparing average minimum to maximum load, from Table 2-5, to average minimum to maximum price, from Figure 2-4; price changes significantly more than load in all markets except Scandinavia. (The same information on weekdays and weekends is shown in Section 2.8.5.) A visualization of this comparison is given in Figure 2-10.

- Correlation between hourly or half-hourly price and load is above 0.5 in three markets, Britain, Spain, and Scandinavia. In these three markets price has a relatively linear relationship with load, as shown in Figure 2-8, e.g., high prices tend to be observed when load is high. Note that these markets also showed the least impact from data filtration: a small percentage of days of price history is not distorting the average price behavior in these markets, as described in Section 2.4. The impact, again, is to give a customer a high degree of predictability of price in these markets. By monitoring overall system demand, a power consumer in Britain, Spain, or Scandinavia could form a reasonable expectation of price behaviors.

- The correlation between price and load is intermediate for PJM, Northern California, and South Australia; it becomes increasingly difficult in these markets to link expected price to expected load. Thus, a customer who might link overall system load to weather (e.g. high air conditioning load associated with a heat wave) would have an increasingly difficult time predicting price in these markets.

- The correlation between price and load is below 0.2 in five markets, meaning a consumer could have very little sense of price from system load, or from weather patterns or other events that may impact load. For these markets, high prices are as likely to occur at lower load values as at high values, as shown in Figure 2.8.

- The correlation between price and load is negative for the Netherlands. One speculation is that this may be due to the majority of the trading of power being done outside of the market. In particular, by the end of 2002, the volume traded in the deregulated market APX had grown to an average of over 38,000 MWh a day, but this presents only about 15% of the net electricity consumption in the Netherlands (see, APX Corporate at http://www.apx.nl/home.html).

These results are consistent with the findings of others. In particular, in a recent work, Vucetic *et al.* (2001) explored the ability of load to predict power cost in California for the period April 1998 through September 1999. One interesting finding was that if price is modeled against load in a third order polynomial model, then additional data on the hour and day does not significantly improve the predictive ability of the model. Load therefore contains substantially the same diurnal variance data as price, and the limited correlation between price and load indicates that other factors are significant drivers of price. Mount *et al.* (2000) found that in three U.S. markets: PJM, New England and California, periods of high price were more likely to occur during periods of high load, but the correlation is not high. Wolak (1999) found that the ability of a time series to predict price is lower at times of high load. He also noted that the ability to model price varies between markets.

In one market, Britain, total available generation capacity as well as load is available on a half-hour basis. Figure 2-11 shows the normalized average weekday and weekend price versus both average load and average excess generation capacity, i.e., available capacity minus actual load. For the aggregate data set the correlation between half-hour price and load is 0.58, between price and available generation is 0.48, and between price and excess generation capacity is -0.20. That price has a negative correlation to excess generation capacity is expected, but it can be noted that load in Britain has a far better predictor of power price than the reported available excess generation capacity.

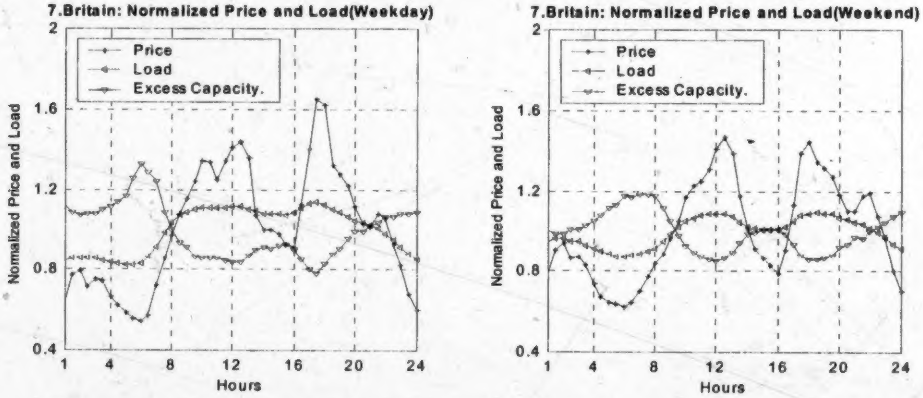

Figure 2-11 Normalized Average Weekday and Weekend Prices vs. Both Average Load and Average Excess Generation Capacity in Britain.

2.6 Discussion

In an ideal power market, consumers would modify their behavior in response to price signals. In practice, most consumers do not do this. Technical reasons for this include an absence of information about power price and an absence of real time metering for small and medium sized power consumers. Market reasons for this occur when the consumer is unable to anticipate future price.

This study confirms that there are significant differences between deregulated markets in the ability of a knowledgeable consumer to anticipate power price. Britain, Spain and Scandinavia show a high degree of predictability of price. Average diurnal price is reliable and not heavily influenced by a small percentage of days. Load and price are well correlated, allowing a customer to link forecasted weather to expected power price. In this kind of market, a customer might accept RTP and face an open market, scheduling power consuming activities such as clothes drying or welding to periods of expected low price through DSM. A similar consumer in South Australia would find little predictability in power price: diurnal price patterns are irregular and highly influenced by a small percentage of days of price excursions, and the correlation between load and price is limited. It is far riskier to accept RTP and face an open power market in Australia; the pressure to hedge and escape the short-term signals coming from price is higher.

The author has not explored policies that contribute to the large difference in deregulated power markets. One area of future research is an exploration of whether market predictability improves with age: does a mature market become more understandable to a consumer.

2.7 Conclusions

All of the power markets in this study are industrialized countries with high per capita GDP's[1]. Despite this common economic base, power price in deregulated markets shows fundamentally different patterns. North American markets show a consistent monotonic diurnal price pattern on weekdays, while all other markets show either a morning and evening price peak or choppy multiple peaks. Deregulated power prices differ between markets in average maximum vs. minimum price and weekday to weekend average price, which create the incentive to time shift power consuming activities. Deregulated markets also differ in the extent to which a small fraction of the total days shape the average pattern and value of hourly or half-hourly price. Deregulated markets show a wide variation in the correlation between load and price.

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[1] GDP, Gross Domestic Product, is the value of goods and services produced in an area.

Some deregulated markets, most notably Britain, Spain and Scandinavia, show patterns that can lead a customer to shape consumption behaviors because of a relatively high degree of predictability of price. Diurnal patterns are consistent and reliable, and the correlation between load and price is high. Other markets, for example, South Australia, have patterns that are hard for a customer to interpret, and hence have a higher incentive for the customer to escape risk through hedging mechanisms.

2.8 Additional Information of Diurnal Patterns

2.8.1 Web Sites for Power Pools / Markets

Table 2-6 Web Sites for Power Pools/Markets

Market	Data Source	Some Useful Website	Currency Used
Canada: Alberta	Power Pool of Alberta	www.powerpool.ab.ca, www.aeso.ca	CAD
USA: Southern California	Cambridge Energy Research Associates, University of California Energy Institute	www.calpx.com	USD
USA: Northern California	Cambridge Energy Research Associates, University of California Energy Institute	www.calpx.com	USD
USA: PJM	Pennsylvania-New Jersey-Maryland	www.pjm.com	USD
USA: New England	ISO New England Power Pool	www.iso-ne.com	USD
Germany: Leipzig	Leipzig Power Exchange (LPX) (Merged and renamed as European Energy Exchange (EEX) from 2002)	www.lpx.de or www.eex.de	DEM
Netherlands	Amsterdam Power Exchange	www.apx.nl	EURO
Britain	Cambridge Energy Research Associates	www.elecpool.com, www.elexon.com	GBP
Spain	Spanish Power Exchange	www.omel.es, www.ree.es	EURO
Scandinavia	The Nordic Power Exchange	www.nordpool.no	NOK
Australia: South Australia	Australian National Electricity Market Management Company Limited	www.nemmco.com.au, www.electricity.net.au	AUD
Australia: Snowy	Australian National Electricity Market Management Company Limited	www.nemmco.com.au, www.electricity.net.au	AUD
Australia: New South Wales	Australian National Electricity Market Management Company Limited	www.nemmco.com.au, www.electricity.net.au	AUD
Australia: Queensland	Australian National Electricity Market Management Company Limited	www.nemmco.com.au, www.electricity.net.au	AUD
Australia: Victoria	Australian National Electricity Market Management Company Limited	www.nemmco.com.au, www.electricity.net.au	AUD
New Zealand: Benmore	New Zealand Electricity Market	www.nzelectricity.co.nz, www.m-co.co.nz	NZD
New Zealand: Haywards	New Zealand Electricity Market	www.nzelectricity.co.nz, www.m-co.co.nz	NZD
New Zealand: Otahuhu	New Zealand Electricity Market	www.nzelectricity.co.nz, www.m-co.co.nz	NZD

Note: The price unit used in Spain is Euro cents per Kilowatt (KWh), all other markets use local currency unit per Megawatt hour (MWh) as the price unit.

2.8.2 Maximum and Minimum Daily Power Prices

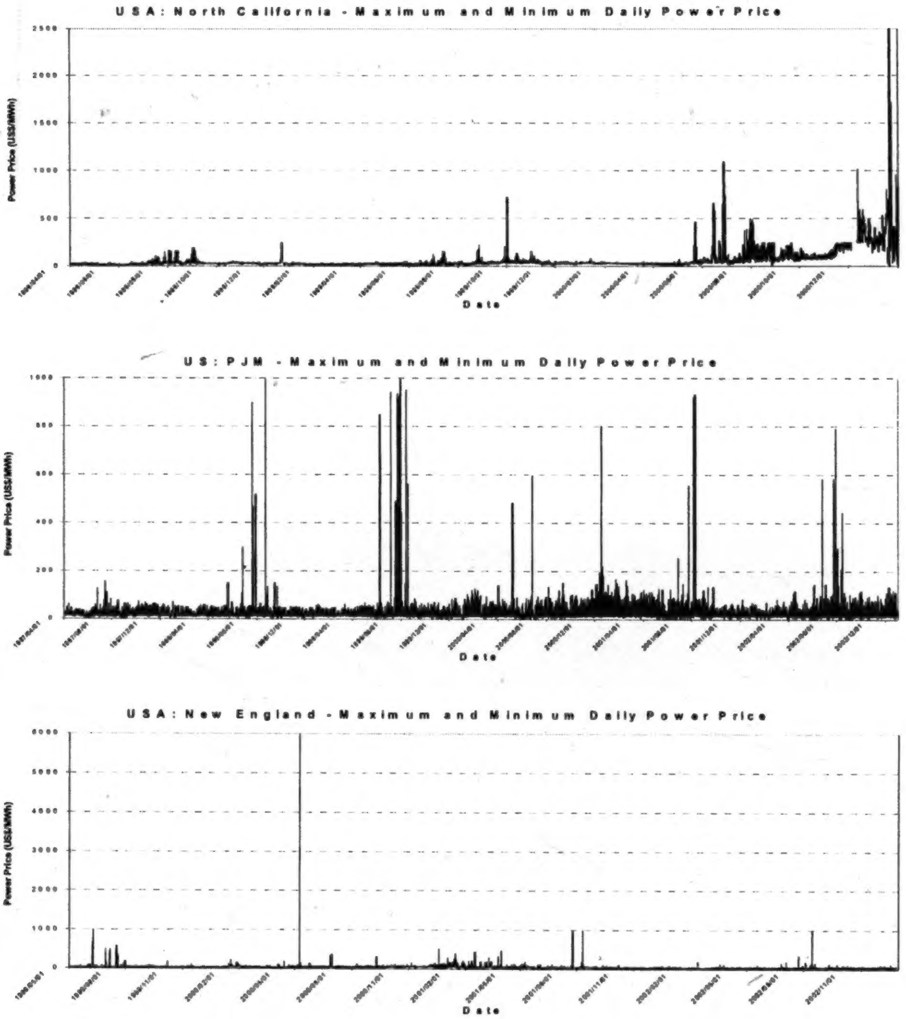


Figure 2-12 Maximum and Minimum Daily Power Prices in the U.S.

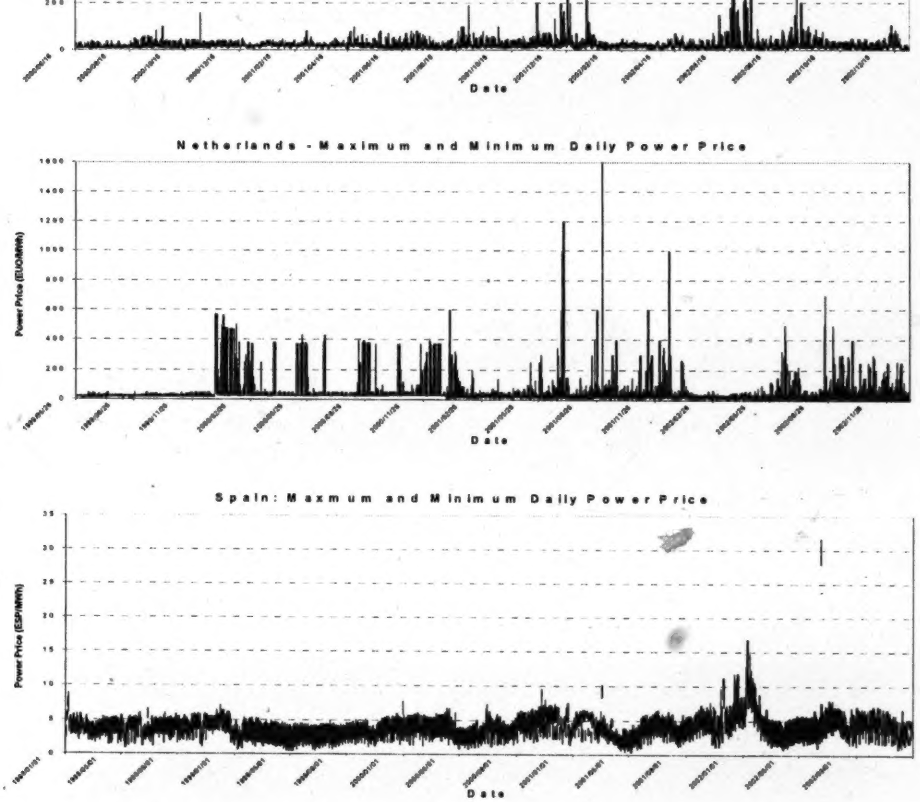


Figure 2-13 Maximum and Minimum Daily Power Prices in Europe.

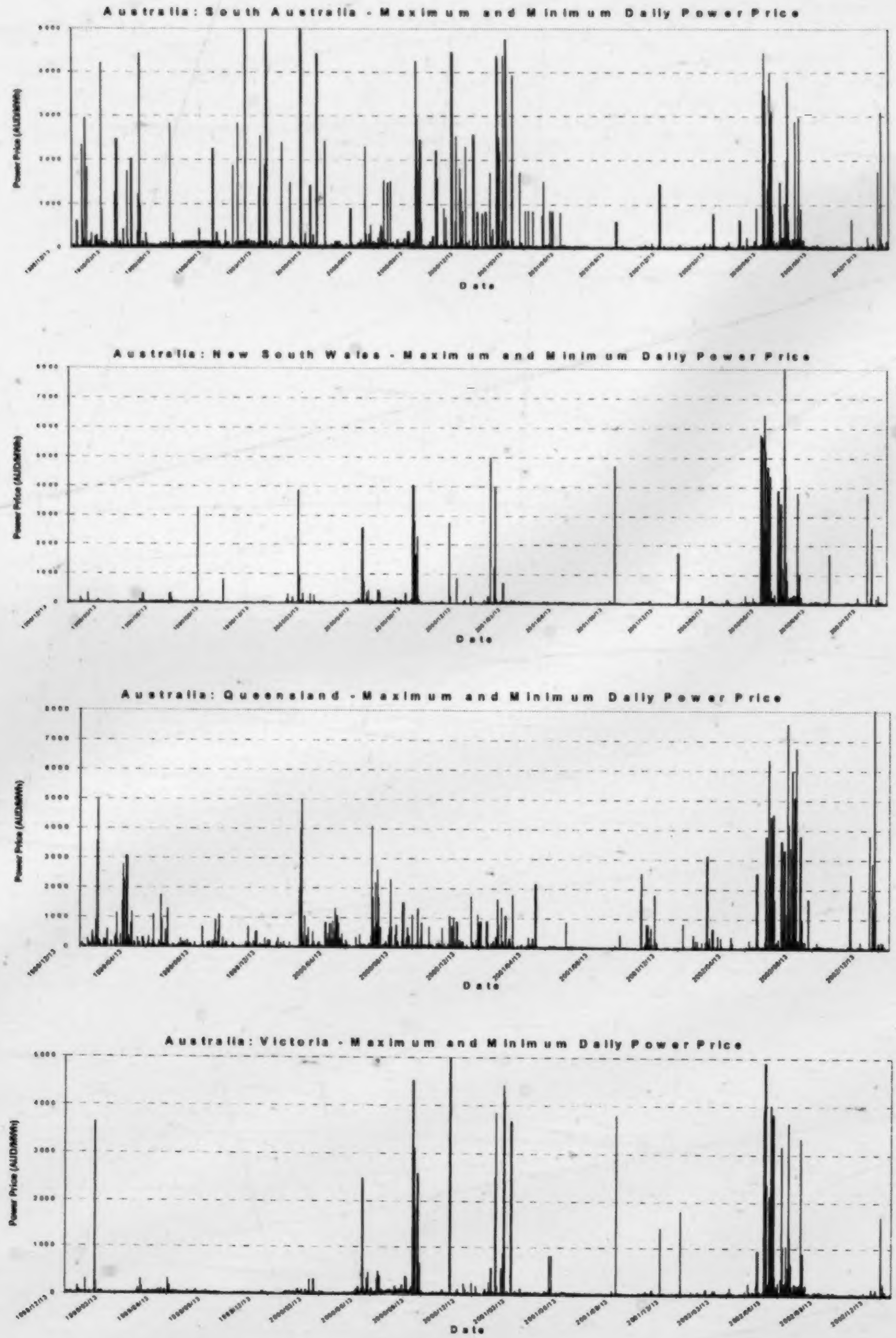


Figure 2-14 Maximum and Minimum Daily Power Prices in Australia.

2.8.3 Detailed Cross Correlation in Power Prices Between Markets

Table 2-7 Cross Correlation in Power Prices Between Markets

Markets	Short Name	PPOA	SCal	NCal	PJM	NEPOOL	LPX	APX	UK	OMEL	Nord Pool	NEMSA	NEMSNOWY	NEMNSW	NEMQLD	NEMVIC	NZEMBEN	NZEMHAY	NZEMOTA
Canada: Alberta	**PPOA**	1.00																	
USA: Southern California	**SCal**	0.42	1.00																
USA: Northern California	**NCal**	0.45	**0.93**	1.00															
USA: PJM	**PJM**	0.11	0.09	0.10	1.00														
USA: New England	**NEPOOL**	0.07	0.08	0.08	0.26	1.00													
Germany: Leipzig Exchange	**LPX**	0.06	0.31	0.31	0.12	0.07	1.00												
Netherlands	**APX**	0.12	0.08	0.10	0.06	0.05	0.42	1.00											
Britain	**UK**	0.05	-0.03	0.00	0.09	0.06	0.48	0.29	1.00										
Spain	**OMEL**	0.14	0.06	0.13	0.13	0.02	0.39	0.22	0.37	1.00									
Scandinavia	**Nord Pool**	-0.04	0.22	0.17	0.04	0.03	0.15	0.06	0.11	0.08	1.00								
Australia: South Australia	**NEMSA**	0.05	0.01	0.02	0.01	0.01	0.02	0.03	0.05	0.04	-0.02	1.00							
Australia: Snowy	**NEMSNOWY**	0.05	0.07	0.09	0.02	0.01	0.02	0.02	0.00	0.06	0.01	0.46	1.00						
Australia: New South Wales	**NEMNSW**	0.04	0.07	0.08	0.02	0.01	0.01	0.01	0.00	0.05	0.01	0.38	**0.88**	1.00					
Australia: Queensland	**NEMQLD**	0.02	0.00	0.01	0.01	0.01	0.02	0.03	0.16	0.05	0.03	0.10	0.30	0.39	1.00				
Australia: Victoria	**NEMVIC**	0.06	0.05	0.07	0.01	0.01	0.02	0.02	0.01	0.05	0.00	0.61	0.61	0.52	0.16	1.00			
New Zealand: Benmore	**NZEMBEN**	0.02	0.01	0.03	0.09	0.04	0.01	0.02	0.17	0.12	0.10	-0.01	0.02	0.02	0.02	0.01	1.00		
New Zealand: Haywards	**NZEMHAY**	0.03	0.03	0.04	0.09	0.04	0.02	0.03	0.20	0.14	0.14	-0.01	0.03	0.02	0.03	0.02	**0.95**	1.00	
New Zealand: Otahuhu	**NZEMOTA**	0.09	0.09	0.10	0.10	0.05	0.05	0.06	0.21	0.17	0.14	0.01	0.04	0.03	0.06	0.03	**0.88**	**0.95**	1.00

Note:

1: The correlations between any two markets are based on the maximum periods of data overlap.

2: For different frequency prices (hourly or half-hourly), correlations are based on hourly prices with half-hourly prices converted to hourly prices by averaging.

2.8.4 Effect of Data Filtration

2.8.4.1 Effect of Data Filtration on Diurnal Price Patterns

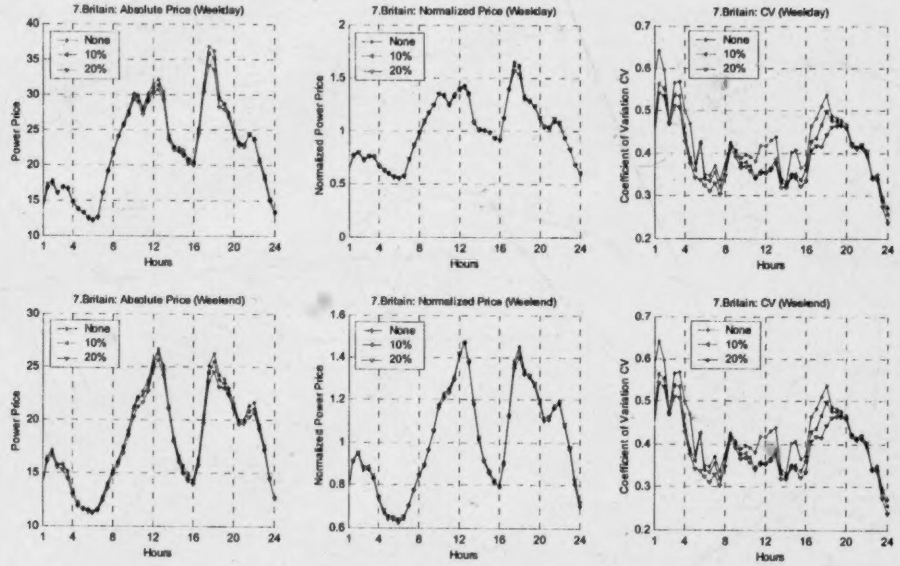


Figure 2-15 Effect of Data Filtration: Britain.

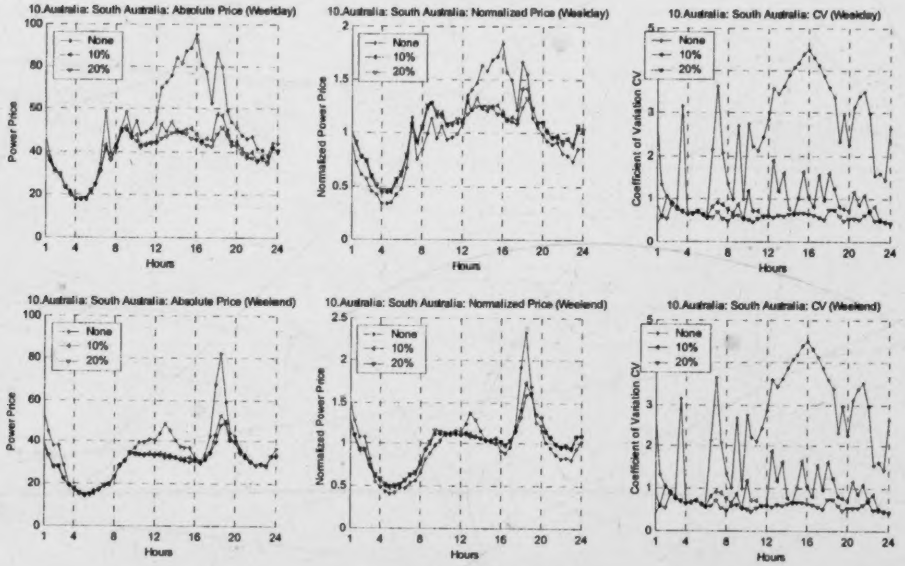


Figure 2-16 Effect of Data Filtration: South Australia.

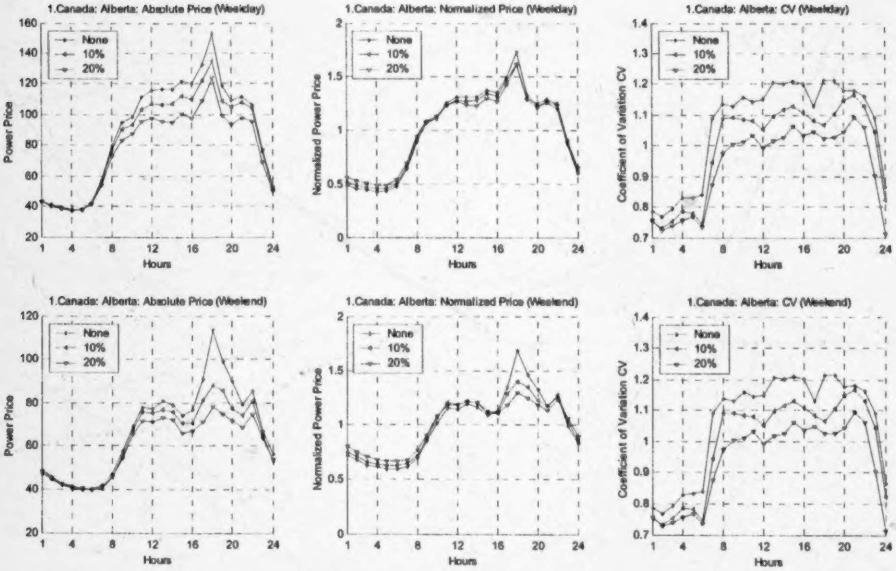


Figure 2-17 Effect of Data Filtration: Alberta.

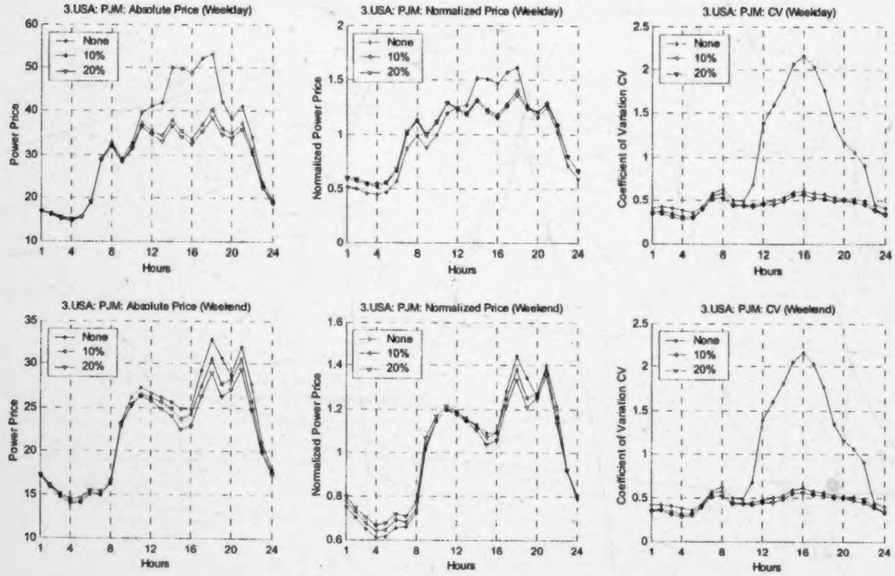


Figure 2-18 Effect of Data Filtration: PJM.

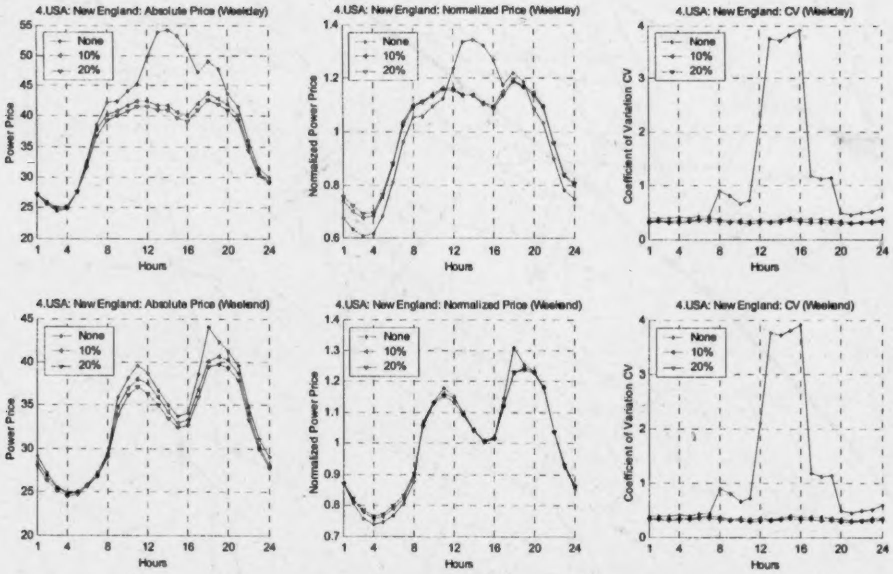


Figure 2-19 Effect of Data Filtration: New England.

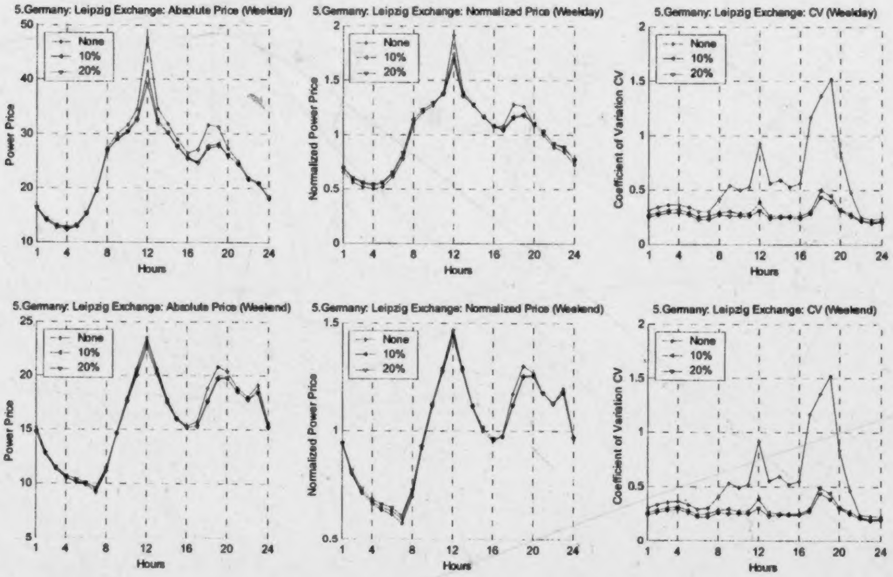


Figure 2-20 Effect of Data Filtration: Leipzig.

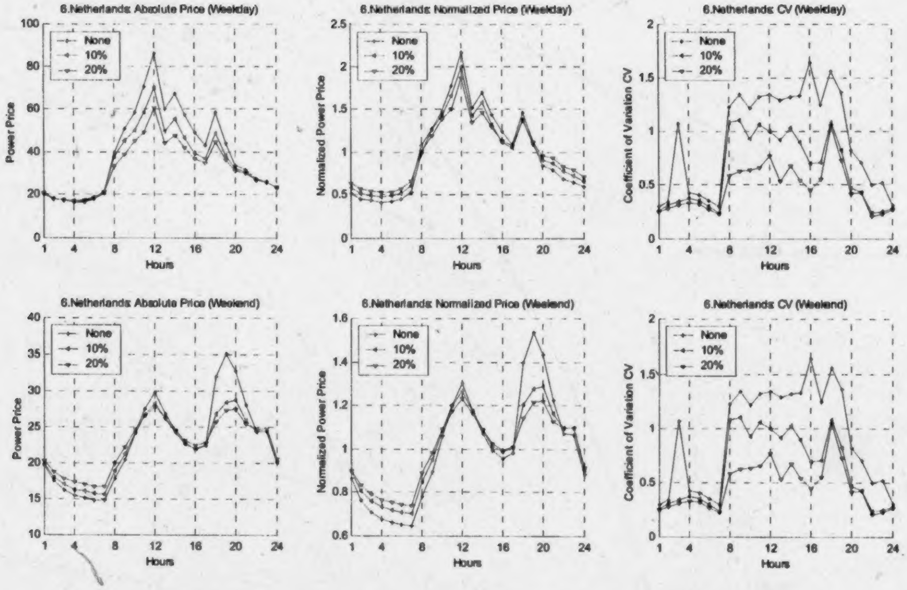


Figure 2-21 Effect of Data Filtration: Netherlands.

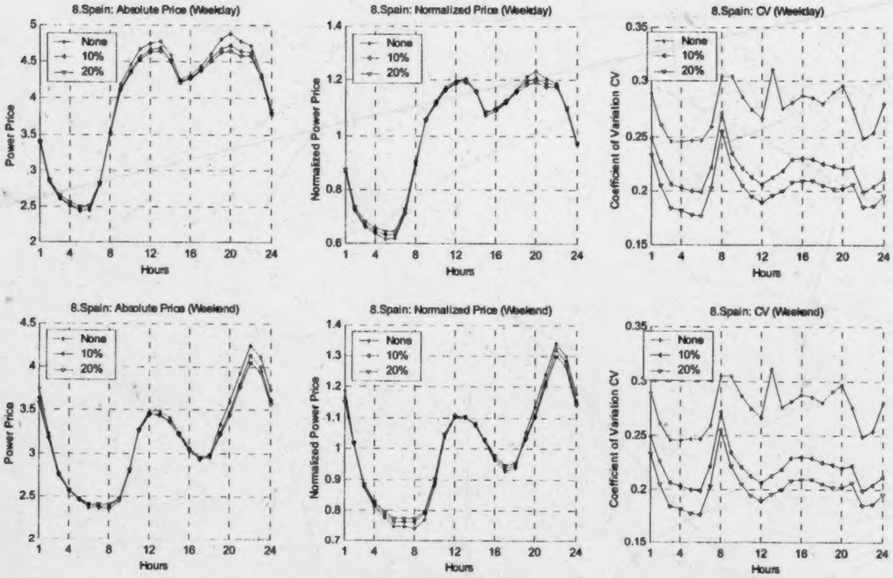


Figure 2-22 Effect of Data Filtration: Spain.

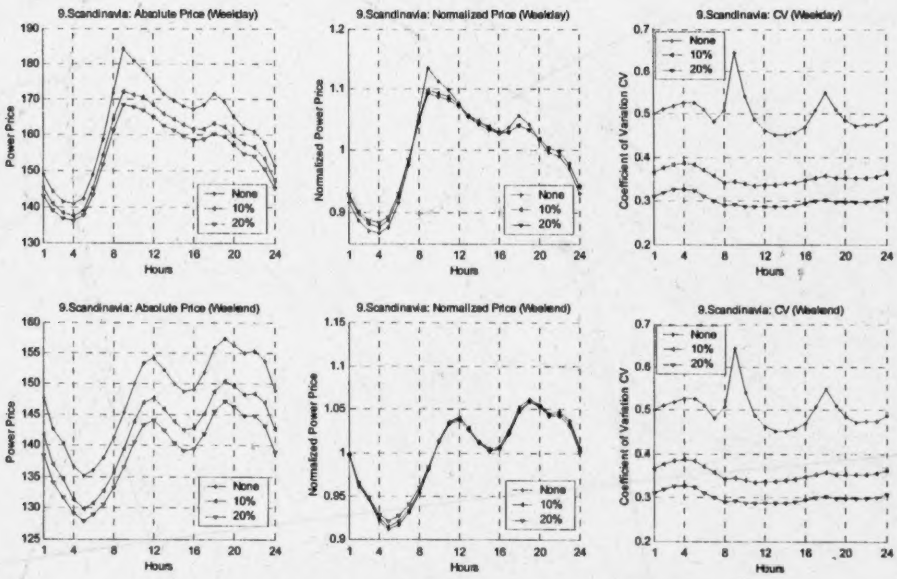


Figure 2-23 Effect of Data Filtration: Scandinavia.

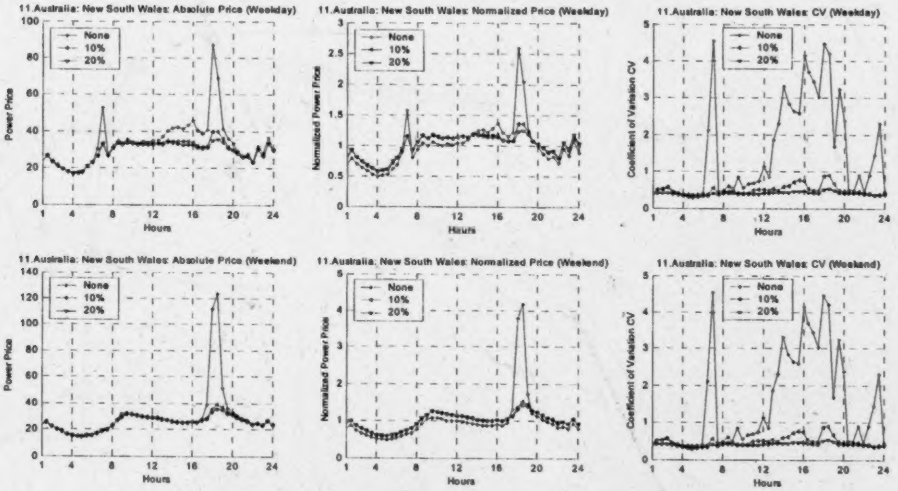


Figure 2-24 Effect of Data Filtration: New South Wales.

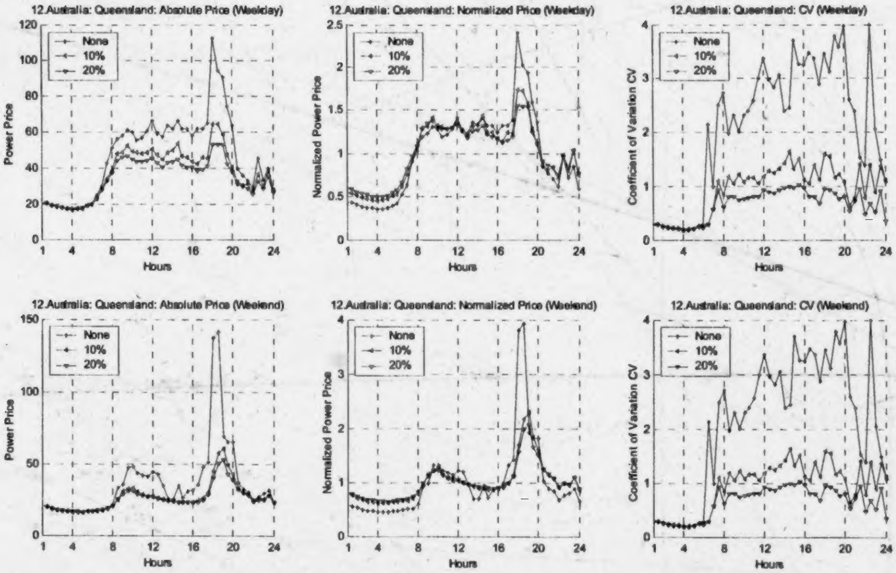


Figure 2-25 Effect of Data Filtration: Queensland.

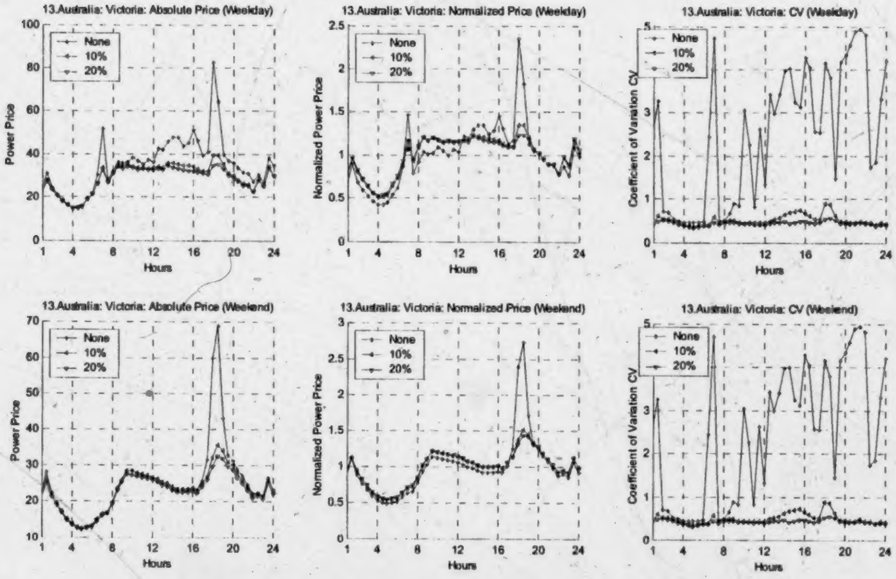


Figure 2-26 Effect of Data Filtration: Victoria.

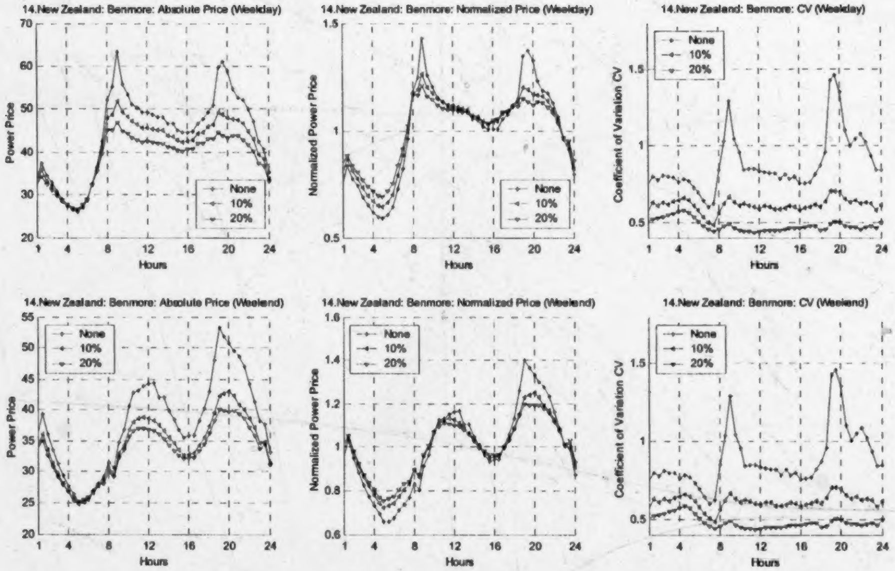


Figure 2-27 Effect of Data Filtration: New Zealand.

2.8.4.2 Effect of Data Filtration on WD/WEAPR

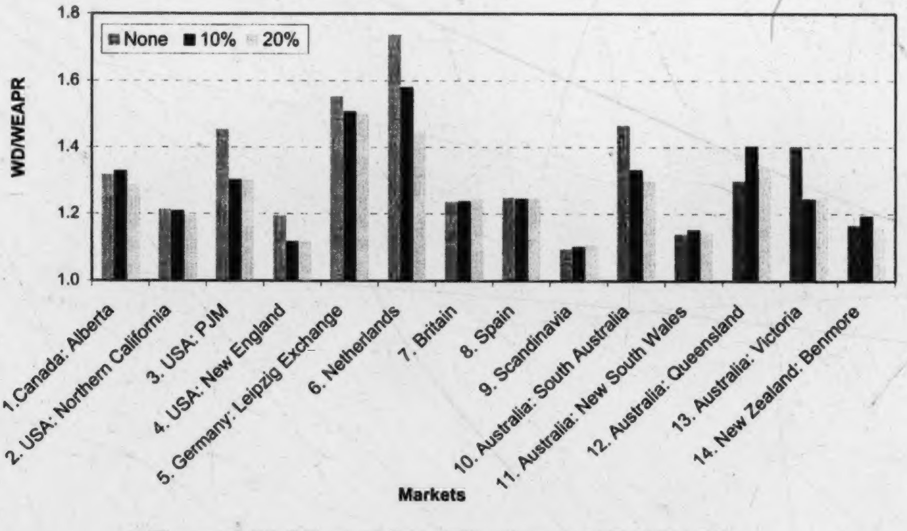


Figure 2-28 Effect of Data Filtration on WD/WEAPR.

2.8.4.3 Effects of Data Filtration on Weekend Prices

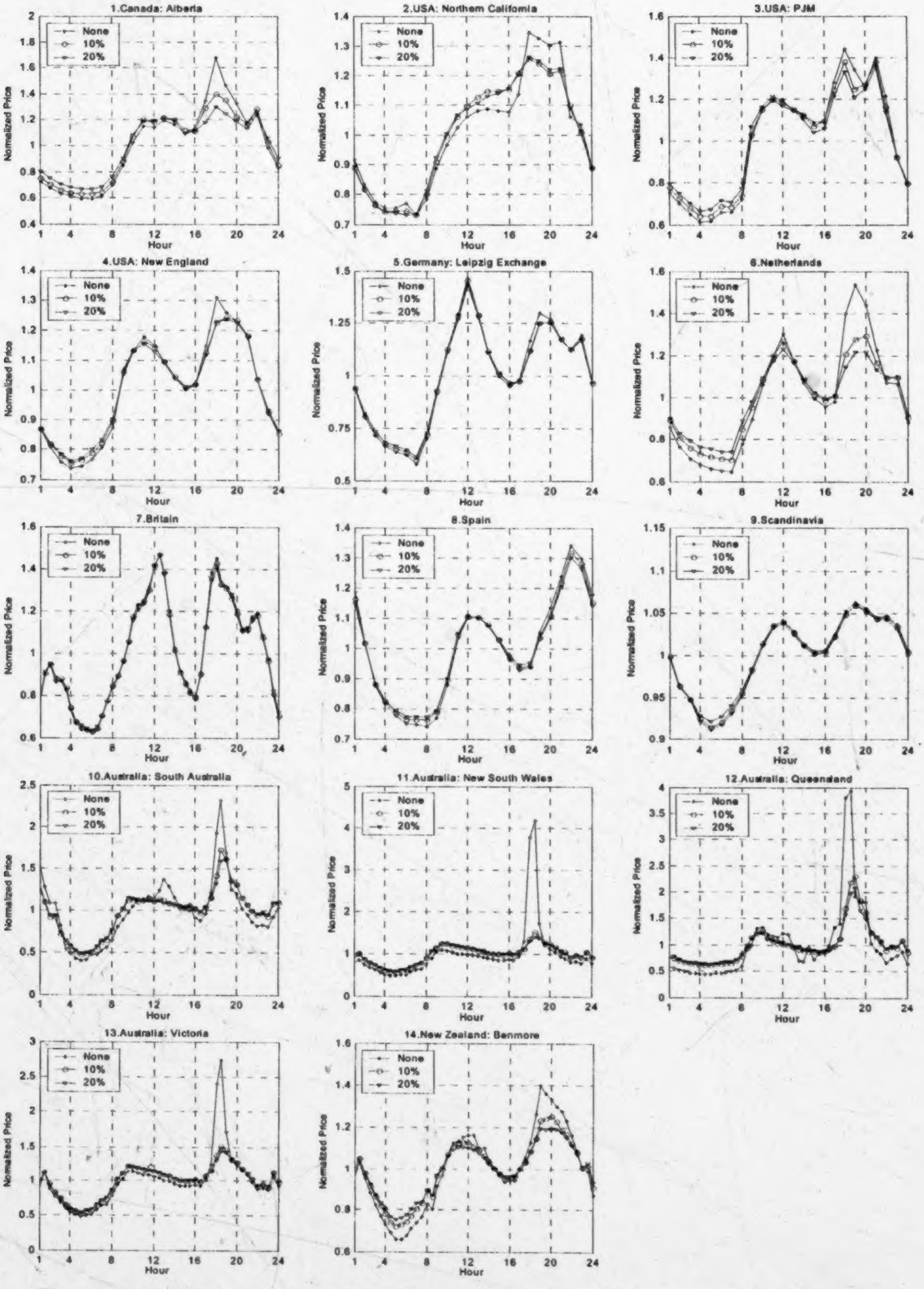


Figure 2-29 Effect of Data Filtration on Normalized Weekend Diurnal Pattern Power Prices.

Table 2-8 Effect of Data Filtration on Weekend Prices

							Impact of Data Filtration			
	Average Weekend Price (WEAP)			Max/Min Ratio (WER)			% Change of WEAP		% Change of WER	
Market	**None**	**10%**	**20%**	**None**	**10%**	**20%**	**10%**	**20%**	**10%**	**20%**
1. Canada: Alberta	67.6	63.0	60.0	2.84	2.22	1.95	6.72	11.18	21.87	31.48
2. USA: Northern California	54.1	44.4	37.5	1.84	1.72	1.73	18.08	30.80	6.25	5.98
3. USA: PJM	22.8	22.1	21.7	2.36	2.16	2.04	3.08	5.03	8.69	13.70
4. USA: New England	33.6	32.7	32.1	1.78	1.64	1.62	2.77	4.41	7.40	8.79
5. Germany: Leipzig Exchange	16.0	15.8	15.7	2.54	2.44	2.35	1.60	1.83	3.93	7.24
6. Netherlands	22.9	22.2	22.5	2.38	1.84	1.67	2.81	1.69	22.64	30.08
7. Britain	18.1	17.8	17.5	2.36	2.33	2.30	1.28	3.21	0.86	2.31
8. Spain	3.2	3.1	3.1	1.81	1.73	1.68	1.33	1.61	4.21	6.75
9. Scandinavia	148.1	142.0	138.8	1.17	1.16	1.15	4.18	6.29	0.57	1.33
10. Australia: South Australia	35.3	30.5	30.1	5.75	3.64	3.25	13.54	14.58	36.78	43.50
11. Australia: New South Wales	29.7	25.6	25.1	8.64	2.66	2.40	13.87	15.50	69.26	72.28
12. Australia: Queensland	35.9	26.4	25.5	8.89	3.76	3.23	26.46	29.09	57.67	63.64
13. Australia: Victoria	25.1	23.5	22.6	5.58	2.83	2.63	6.59	9.95	49.26	52.97
14. New Zealand: Benmore	38.0	34.3	33.4	2.12	1.74	1.59	9.72	12.17	18.10	24.89

Note: Units for price are local currency unit per MWh in all markets except Spain where the unit for price is Euro cent per KWh.

2.8.4.4 Effect of Data Filtration on Overall Prices

Table 2-9 Effect of Data Filtration on Overall Prices

	Overall Average Price (OAP)			Max/Min Ratio (OR)			Impact of Data Filtration			
							% Change of OAP		% Change of OR	
Market	**None**	**10%**	**20%**	**None**	**10%**	**20%**	**10%**	**20%**	**10%**	**20%**
1. Canada: Alberta	82.9	77.8	72.4	3.68	3.18	2.90	6.06	12.66	13.43	21.17
2. USA: Northern California	62.4	51.0	42.7	1.84	1.77	1.86	18.27	31.60	3.73	-1.13
3. USA: PJM	30.2	26.9	26.3	3.28	2.56	2.40	10.89	12.81	21.99	26.81
4. USA: New England	38.3	35.5	34.9	1.97	1.71	1.67	7.43	8.98	13.29	15.23
5. Germany: Leipzig Exchange	22.3	21.5	21.4	3.46	3.02	2.85	3.85	4.42	12.85	17.70
6. Netherlands	34.9	31.4	29.6	4.33	3.48	2.99	9.94	15.23	19.76	30.96
7. Britain	21.1	20.9	20.5	2.81	2.73	2.61	1.12	2.89	2.81	7.17
8. Spain	3.7	3.7	3.7	1.89	1.83	1.79	1.45	1.77	3.00	5.35
9. Scandinavia	158.3	152.5	149.7	1.24	1.21	1.19	3.69	5.46	2.82	3.79
10. Australia: South Australia	47.0	37.7	36.6	4.76	3.28	2.91	19.72	22.21	31.16	38.94
11. Australia: New South Wales	32.7	28.4	27.7	5.81	2.40	2.15	13.13	15.17	58.70	62.99
12. Australia: Queensland	43.6	34.0	31.6	7.22	3.73	3.14	21.89	27.44	48.37	56.51
13. Australia: Victoria	32.3	27.6	26.7	5.28	2.64	2.37	14.75	17.49	50.04	55.21
14. New Zealand: Benmore	42.6	39.1	37.2	2.25	1.83	1.65	8.18	12.60	18.79	26.94

Note: Units for price are local currency unit per MWh in all markets except Spain where the unit for price is Euro cent per KWh.

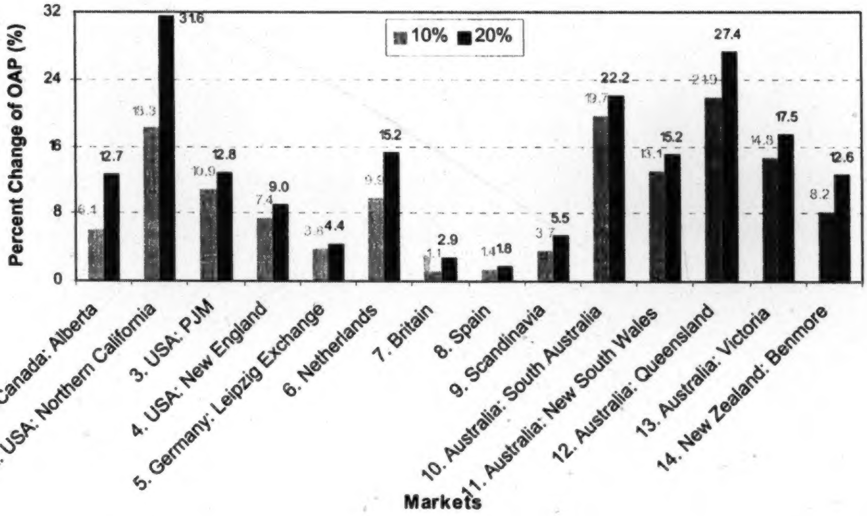
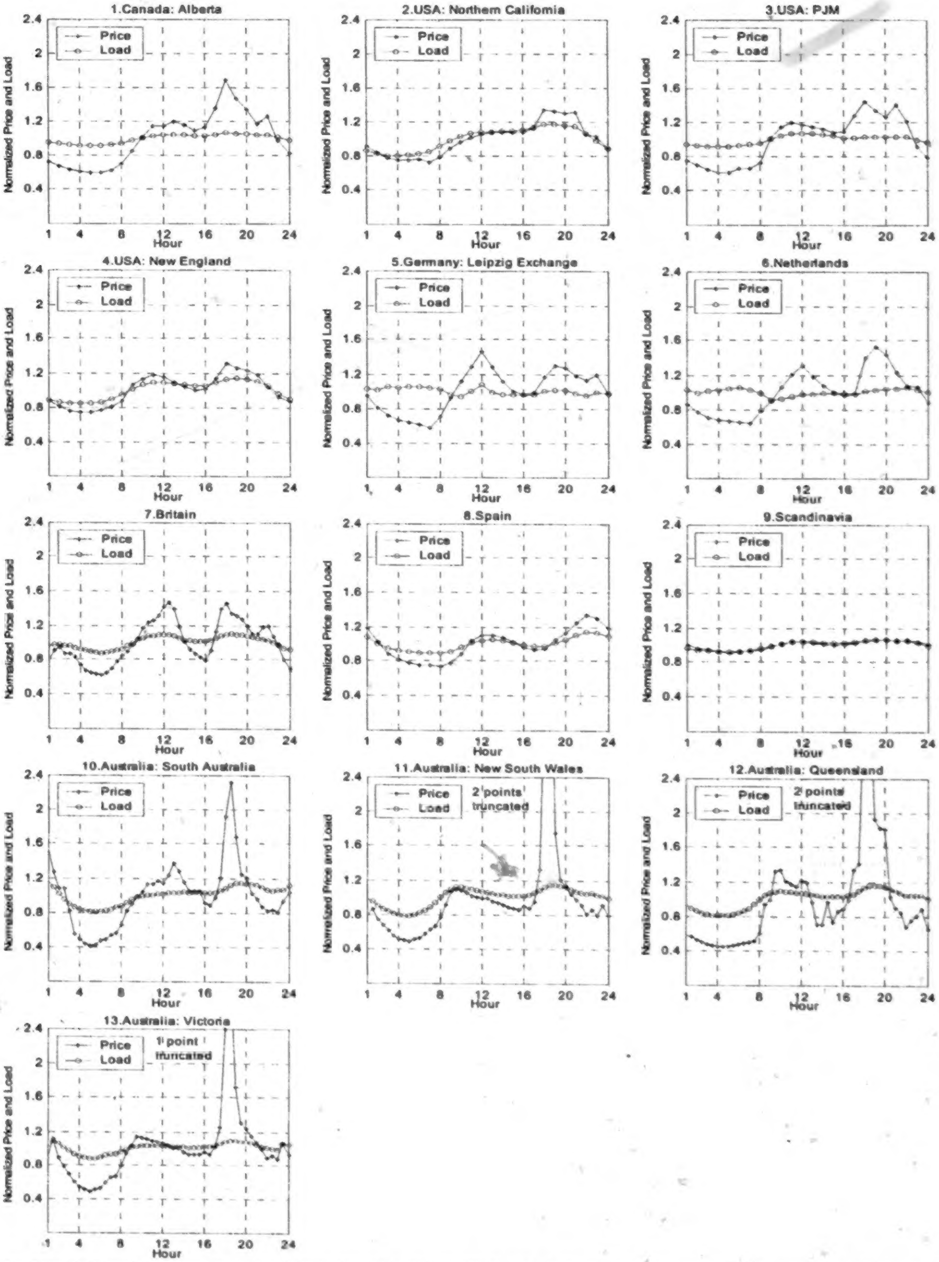


Figure 2-30 Effect of Data Filtration on the Overall Average Price (OAP).

2.8.5 Relationship between Weekend Prices and Load



1.Canada: Alberta

2.USA: Northern California

3.USA: PJM

4.USA: New England

5.Germany: Leipzig Exchange

6.Netherlands

7.Britain

8.Spain

9.Scandinavia

10.Australia: South Australia

11.Australia: New South Wales

12.Australia: Queensland

13.Australia: Victoria

Note: two data points were truncated from for New South Wales and Queensland, respectively, and one datum point was truncated for Victoria

Figure 2-31 Normalized Average Weekend Power Prices and Load.

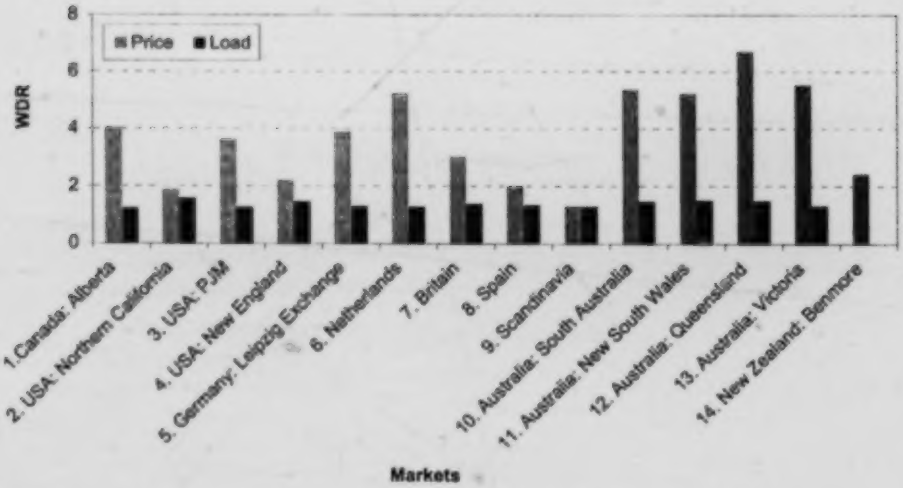


Figure 2-32 Ratios of Maximum to Minimum of Power Prices and Load on Weekdays.

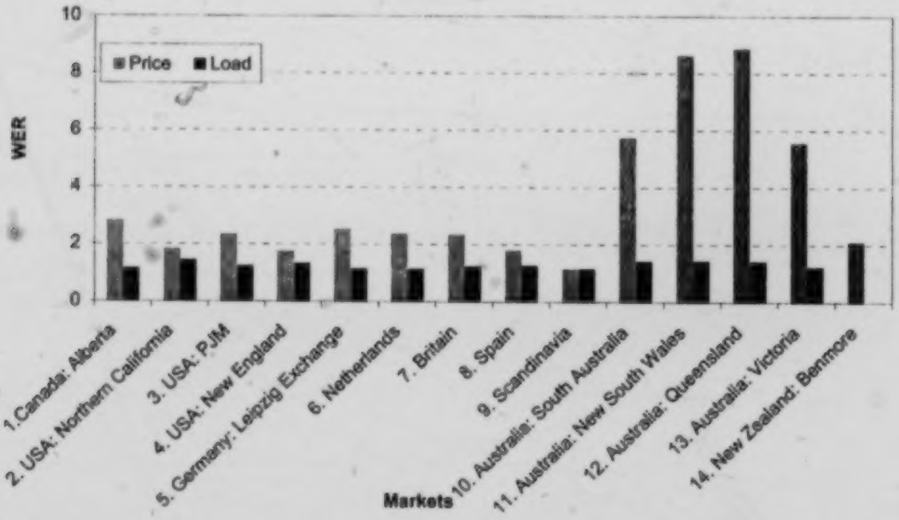


Figure 2-33 Ratios of Maximum to Minimum of Power Prices and Load on Weekends.

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CHAPTER 3 VOLATILITY OF POWER PRICES

Looking at the diurnal pattern of power prices leaves out one key element that affects consumers: how volatile are power prices? Ideally, power prices serve as a signal to consumers to shape their power consumption activities. The willingness of consumers to buy power in open markets with RTP and shape consuming activities based on price variation depends, in part, on the degree of predictability or understanding of the change in power prices. It is expected, for example, that consumers in markets with high and random price volatility would be more prone to hedge their power purchase, an activity that frequently covers the incentive to shape power consumption activities. In this chapter, the difference within and between markets in term of price volatility is examined. The focus is on the hourly rate of change of price.

3.1 Introduction

Electrical power is a basic energy commodity in an industrial society, and a great number of human activities at both work and home depend on it. Because it originated as an essential commodity often supplied by a single corporate entity, electrical power developed in most countries under regulation, with a price prescribed through some form of governmental regulatory process or outright state ownership. In the past 20 years, however, many jurisdictions have deregulated wholesale and retail electrical power prices. As discussed in a previous work (Chapter 2; Li and Flynn, 2004), deregulated electrical power is usually sold through a single central "pool" in order to establish a single visible price. Users and generators are free to hedge the price by side agreements to remit differences between the pool price and the price agreed to in the hedge contract. Studies of individual power markets and comparisons between markets are cited in our previous work.

Because electrical power is not effectively storable in significant quantities, wide intraday and inter-day variations in price occur in deregulated markets;

intraday patterns were explored in Chapter 2 and Li and Flynn (2004). In this chapter, the author looks at volatility in power price, with a focus on the hourly rate of change of price, for numerous deregulated markets.

Our specific focus is looking at power price from the perspective of the consumer of electrical power. Ideally, price is a signal to consumers that shapes consumption, e.g. at times of high price consumers manage demand by changing their activities in order to consume less power. This idea is hard to achieve in deregulated power markets. Small consumers, including domestic and small commercial sites, typically do not have a meter that records time of use, and do not in practice monitor diurnal power price changes because the information is not readily available and it has no impact on them. These consumers are *de facto* forced to be hedged against daily power price fluctuations by the current technology of metering. Larger commercial and industrial customers typically have time of use metering and access to Internet sites that give hourly pricing, and in theory can respond to diurnal price changes. However, scheduling flexibility is limited when the time frame is less than one day. For example, in most jurisdictions when labor is called out it cannot be sent home on short notice, so labor costs cannot be avoided if work is terminated due to a price spike within a day.

Even given these observations, the author believes that deregulated power markets that show a high degree of unpredicted or random volatility will discourage consumer response other than hedging, while in markets with a lower degree of volatility consumers should be more willing to purchase power in the open market and manage demand by tailoring their consumption behaviors based on price. For that reason, the author believes that price volatility is an important metric for deregulated power markets.

3.2 Power Price Data

Hourly or half hourly power price data from 18 different deregulated power markets have been collected. Markets with a cross correlation less than 0.6 have been considered to be sufficiently independent to be treated as a separate market; applying this test, 14 power markets are left for the following analysis.

Table 3-1 summarizes the power price data that is used in this study of volatility. (Details of power price data are described in Chapter 2.)

Table 3-1 Power Price Data for Deregulated Markets

Market	Data Type	Time Period	No. of Data Points	% of Data Cleaned (%)
1.Canada: Alberta	hourly	1996/01/01~2002/12/31	61,368	0.02
2.USA: Northern California	hourly	1998/04/01~2001/01/31	24,888	0.80
3.USA: PJM	hourly	1997/04/01~2002/12/31	50,424	0.21
4.USA: New England	hourly	1999/05/01~2002/12/31	32,184	1.05
5.Germany: Leipzig Exchange	hourly	2000/06/16~2002/12/31	22,296	0.09
6.Netherlands	hourly	1999/05/26~20021/12/31	31,584	0.25
7.Britain	half hourly	1996/01/01~1997/12/31, 1998/03/01~2001/2/28	87,696	0.08
8.Spain	hourly	1998/01/01~2002/12/32	43,824	0.02
9.Scandinavia	hourly	1992/05/04~2002/12/31	93,456	0.01
10.Australia: South Australia	half hourly	1998/12/13~2002/12/31	71,040	0.02
11.Australia: New South Wales	half hourly	1998/12/13~2002/12/31	71,040	0.03
12.Australia: Queensland	half hourly	1998/12/13~2002/12/31	71,040	0.03
13.Australia: Victoria	half hourly	1998/12/13~2002/12/31	71,040	0.03
14.New Zealand: Benmore	half hourly	1996/11/01~2002/12/31	108,096	0.38

Data as received had three kinds of errors: missing data, questionable data and multiple data for a single time period. Specific steps taken to "clean" the data are discussed in Appendix B. Data cleaning is such a small fraction of total data that it is not a significant source of error in the results.

3.3 Power Price Volatility

To look at the differences within and between markets in terms of volatility, the author defines two values of velocity of power price. The first is the daily average rate of hourly change of price expressed as a fraction of the overall (long term) average price in the market, which is called daily velocity based on overall average price (DVOA). DVOA is based on the absolute value of price change, i.e., a change up or down is expressed as a positive fraction. Hence, a DVOA of $0.2hr^{-1}$ means that each hour, on average, the power price changes by 20% of the long term average price in a market. Note that for markets with pricing reset every half hour, price velocity is still calculated on a hourly basis.

DVDA, the daily velocity based on the daily average power price, is similar to DVOA, except that the daily average rate of hourly change of price is expressed as a fraction of the average power price on that day. Again, the absolute value of the hourly price change is used, so a change of price in either direction generates a positive velocity. See Section 3.8.1 for a mathematical definition of DVOA and DVDA.

DVOA gives a sense of the consumer's perception of daily volatility relative to a longer term view of price: what is the hourly change in power price compared to the overall average price. DVOA would more likely influence a consumer's decision to hedge and lock in a long-term price. DVDA gives a sense of the uncertainty a consumer experiences in buying price on a given day, i.e., if the consumer buys power at a given hour, how high is the rate of change of price in subsequent hours of that day. Note that during a price spike, daily average price is high, and DVOA would be higher than DVDA.

The author chooses price velocity, based on the change in hourly or half-hourly price, rather than the variance, based on the square of the difference between actual and average price (some alternate measurements of price volatility are described in Appendix D), because the author believes it more closely parallels what consumers consider when they look at power price markets: if I consume power in this period, how is its price going to compare to the price of power in past and future periods, and to the past and expected future average power price?

This approach is similar but not identical to the one discussed by Mount *et al.* (2000), who compared price volatility in three U.S. markets: PJM, New England, and California, and found evidence of market switching from low price cost based bids to high price market based bids in all three markets. This switch was related to load in New England and California, but not in PJM, which is attributed to the high degree of interconnection in PJM market. Periods of high prices are more likely to occur during periods of high load, but the correlation is not high. This is similar to a finding in the previous work (Chapter 2; Li and Flynn, 2004) that in most deregulated markets the correlation of price to load is low; the correlation is above 0.5 for only three of the 14 markets. Most other analyses of variability of power price have been within a single market, and are often aimed at characterizing volatility for the purpose of predicting price variability or pricing options for future power purchases; see, for example, Niemeyer (2000), Robinson and Baniak (2002). Duffie *et al.* (1999) provided a good overview of the analysis of volatility in futures markets. Masson (1999) reviewed price risk management strategies and specially discussed four markets Scandinavia, Britain, California, and Australia.

Table 3-2 shows the average, maximum values, and the coefficients of variation (CVs, standard deviation divided by mean) of DVOA and DVDA for the 14 markets, ranked in increasing value of the average DVOA, i.e., the first column of numbers in the table. It is clear that normalized average price change differs sharply between deregulated power markets. There is a tenfold range in the average price velocity, and a significant difference in variation in velocity.

Table 3-2 Average, Maximum, and Coefficients of Variation (CVs) of Price Velocity DVOA and DVDA

	Price Velocity DVOA			Price Velocity DVDA		
Market	**Average (hr^{-1})**	**Max (hr^{-1})**	**CV**	**Average (hr^{-1})**	**Max (hr^{-1})**	**CV**
9:Scandinavia	0.03	1.54	0.50	0.03	0.53	0.98
8:Spain	0.09	0.65	2.09	0.09	0.38	2.26
2:USA: Northern California	0.10	3.04	0.46	0.10	0.70	1.57
14:New Zealand: Benmore	0.11	2.03	0.66	0.11	1.31	0.96
7:Britain	0.13	0.53	1.73	0.12	0.41	2.67
4:USA: New England	0.15	13.15	0.36	0.13	0.67	1.70
5:Germany: Leipzig Exchange	0.16	4.77	0.68	0.15	0.85	2.04
13:Australia: Victoria	0.23	14.77	0.28	0.14	1.30	1.04
11:Australia: New South Wales	0.24	10.32	0.29	0.14	1.46	0.91
6:Netherlands	0.25	3.86	0.60	0.19	1.45	1.21
1:Canada: Alberta	0.25	1.60	0.81	0.23	1.13	1.31
3:USA: PJM	0.27	5.01	0.70	0.23	1.06	2.29
10:Australia: South Australia	0.31	11.66	0.34	0.19	1.52	0.98
12:Australia: Queensland	0.40	24.66	0.31	0.21	1.54	0.94

The distribution of velocity values also illustrates significant differences between deregulated power markets. Figure 3-1 shows the reverse cumulative distribution (RCF) of the weekday and weekend price velocity in each of the 14 markets, for each of the two velocities; the plots are truncated at a price velocity of $1hr^{-1}$. Table 3-3 shows the fraction of days for which the two weekday velocities exceed $0.1hr^{-1}$, $0.2hr^{-1}$, and $0.5hr^{-1}$ (the choice of these values is arbitrary). Markets in Table 3-3 are ordered in increasing number of days for which DVOA exceeds 20% of the overall average price in the market. (i.e., the 2nd column of numbers in Table 3-3). The same information for weekend and overall prices are given in Section 3.8.2.

Several observations emerge from an inspection of Figure 3-1 and Table 3-3:

- There are significant differences in the distribution of price velocity between markets. Compare, for example, Alberta and Britain. In Alberta, the average hourly price change exceeded 50% of the long-term average price on about 18% of the days; while in Britain this occurred in only two of the 1827 days in the sample set. To a consumer, this large price change on an hourly basis must seem like a highly chaotic market, and again this kind of market chaos creates a higher driving force for consumers to opt for by hedging. It is interesting to note that despite its press coverage of price excursions, Northern California does not show a high price velocity compared to other markets. This suggests that the issue in the California power crisis was high prices, not high price variability.

- From the perspective of distribution of price velocity, specifically not having a high fraction of days of high rate of change of price, Scandinavia, Spain, Northern California, and Britain have a small fraction of "high velocity" days, while Alberta, PJM, the Netherlands, South Australia, and Queensland have a high fraction. The remaining markets have intermediate values.

- In all markets, the price velocity on weekdays is higher than that on weekends. The difference between weekday and weekend price velocity is however small in all markets except Alberta, PJM, the Netherlands, and Queensland. The reasons for this difference in these four markets have not been explored yet.

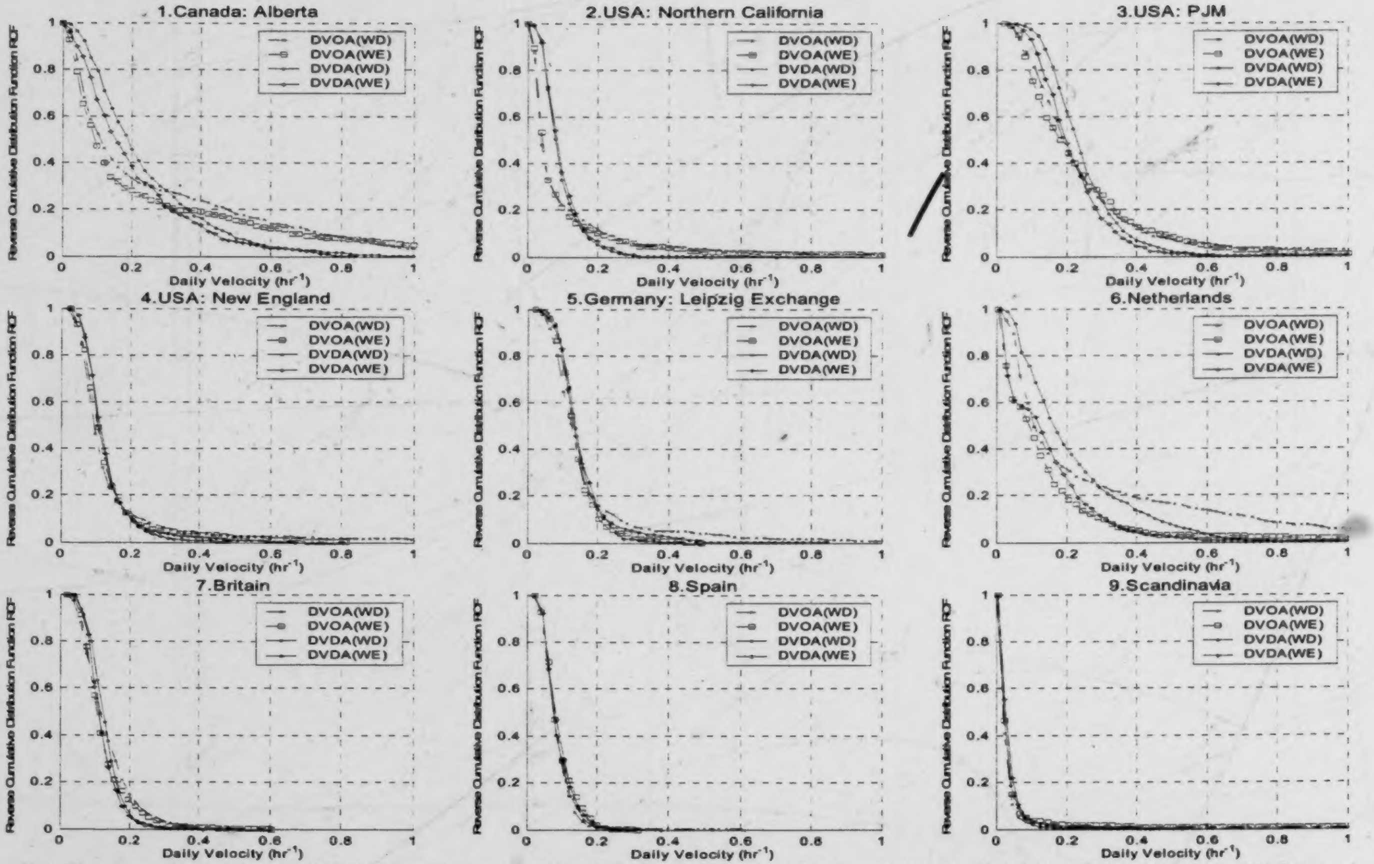

Figure 3-1 Reverse Cumulative Distribution Function (RCF) of the Weekday (Wd) and Weekend (We) Price Velocity DVOA and DVDA.

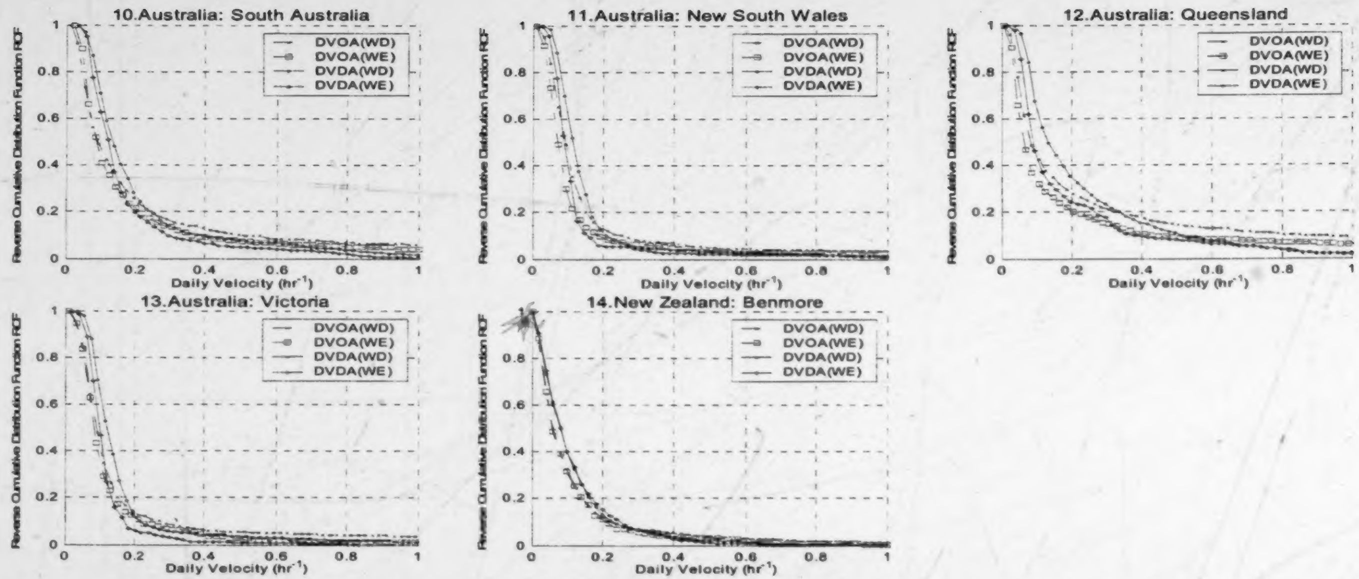

Figure 3-1 Reverse Cumulative Distribution Function (RCF) of the Weekday (Wd) and Weekend (We) Price Velocity DVOA and DVDA (Continued).

Table 3-3 Fraction of Days for Which Weekday Price Velocity DVOA and DVDA Exceed 0.1hr^{-1}, 0.2hr^{-1}, and 0.5hr^{-1}

	Fraction of Days (%)					
	DVOA (hr^{-1})			DVDA (hr^{-1})		
Market	**>0.1**	**>0.2**	**>0.5**	**>0.1**	**>0.2**	**>0.5**
9:Scandinavia	1.99	0.66	0.27	2.11	0.47	0.04
8:Spain	17.36	0.88	0.05	25.85	1.15	0.00
11:Australia: New South Wales	32.50	11.08	4.46	47.57	8.85	3.18
14:New Zealand: Benmore	31.93	11.41	3.33	39.65	13.81	1.78
4:USA: New England	45.86	11.63	2.54	49.52	9.02	0.52
2:USA: Northern California	21.50	11.67	3.09	33.17	5.50	0.39
7:Britain	48.49	12.04	0.05	67.27	5.58	0.00
13:Australia: Victoria	35.68	12.57	4.46	58.11	9.93	2.77
5:Germany: Leipzig Exchange	51.78	13.02	3.23	66.52	10.76	0.22
10:Australia: South Australia	40.07	22.23	9.46	56.42	22.36	6.76
12:Australia: Queensland	40.00	25.41	13.04	50.47	29.59	9.39
6:Netherlands	48.86	26.60	13.53	64.82	34.12	5.70
1:Canada: Alberta	50.73	32.39	18.43	75.91	43.34	7.66
3:USA: PJM	73.74	40.92	6.71	92.05	50.62	1.46

3.4 Unexpected Price Velocity

A thoughtful consumer will expect some variability in power prices, which arises from the diurnal pattern; for example, on average, power always costs more at 3 P.M. than it does at 3 A.M., so there are predictable price movements over the course of a day in each market. In the previous work (Chapter 2; Li and Flynn, 2004), the author showed the average diurnal pattern for each of the 14 markets in this study. Figure 3-2 shows the average hourly weekday and weekend price for two of the 14 markets, the Netherlands and Scandinavia. These two markets illustrate that diurnal price patterns, which reflect among other things the mix of generation in each market, differ sharply: the weekday average maximum to minimum price ratio in the Netherlands 5.2, while in Scandinavia it is 1.3. Hence, a thoughtful consumer in the Netherlands will expect more variability in hourly power price than in Scandinavia.

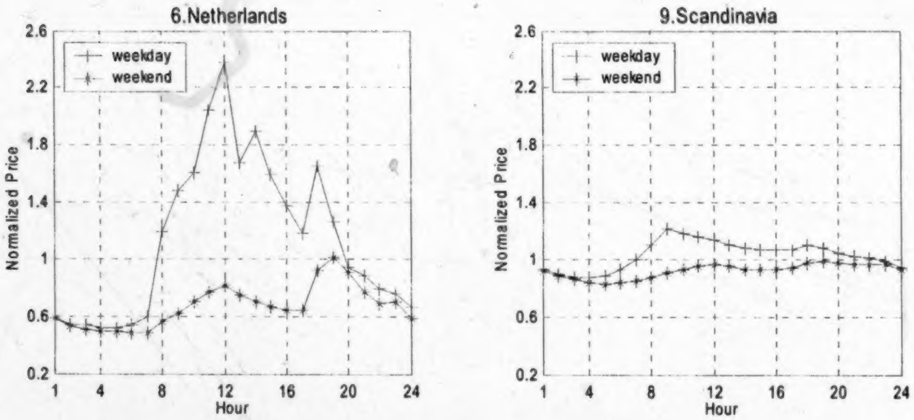

Figure 3-2 Average Hourly Price for Netherlands and Scandinavia.

The author uses the average diurnal price pattern to calculate two values of expected daily velocity, the expected velocity relative to the long-term overall average price (EVOA) and the expected velocity relative to the daily average price (EVDA), for each market. DVOA will equal EVOA if the price of power on a given day follows its historic average pattern exactly. Subtracting EVOA from DVOA can generate the unexpected velocity of power price (UVOA). As with DVOA, UVOA is a daily value: the daily average of hourly price change (absolute value) minus the component that is expected from the average diurnal price pattern. Note that UVOA can have a negative value, which will occur on a day in which the actual price variability is less than that expected from the average diurnal price pattern. See Section 2.8.3 for a mathematical definition of EVDA, UVDA, EVOA and UVOA.

Table 3-4 shows EVOA for each of the 14 markets in this study, and also shows the values of UVOA that is exceeded on 30%, 20%, and 10% of days (again, the choice of these values is arbitrary). The markets are ranked in the increasing number of the UVOA for which the fraction of days exceeded 20% of the total days in the markets, i.e., the third column of numbers in the table. Note that the Netherlands shows the highest value of EVOA, 0.17hr^{-1}, because of its high maximum to minimum diurnal pattern, and that the value of EVOA for Scandinavia is low, 0.02hr^{-1}, for the opposite reason.

Table 3-4 Expected Price Velocity EVOA and Unexpected Price Velocity UVOA that Is Exceeded on 10%, 20% and 30% of Days

Market	**EVOA (hr^{-1})**	**UVOA (hr^{-1}) That Is Exceeded on Fraction of Days**		
		>30%	**>20%**	**>10%**
11:Australia: New South Wales	0.16	-0.02	0.00	0.10
9:Scandinavia	0.02	0.02	0.02	0.04
13:Australia: Victoria	0.15	-0.02	0.02	0.12
8:Spain	0.06	0.06	0.06	0.08
2:USA: Northern California	0.05	0.03	0.07	0.19
5:Germany: Leipzig Exchange	0.13	0.03	0.07	0.13
4:USA: New England	0.06	0.08	0.10	0.18
14:New Zealand: Benmore	0.05	0.07	0.11	0.17
7:Britain	0.08	0.07	0.11	0.15
6:Netherlands	0.17	0.01	0.13	0.53
10:Australia: South Australia	0.11	0.06	0.14	0.38
12:Australia: Queensland	0.15	0.01	0.15	0.63
3:USA: PJM	0.10	0.17	0.23	0.35
1:Canada: Alberta	0.11	0.14	0.36	0.66

Figure 3-3 shows the reserve cumulative distribution (RCF) of UVOA for each of the 14 markets. Note that the plot is truncated at the UVOA of $0.5hr^{-1}$. Figure 3-3 offers a powerful comment on the markets as seen by consumers: deregulated markets vary widely in their predictability. Compared to the other markets, Alberta, PJM, Queensland, South Australia, and the Netherlands have significantly higher unexpected price velocity, while Scandinavia, Spain, Victoria and New South Wales have significantly lower unexpected velocity. Note that market size does not appear to drive price volatility. Alberta and New Zealand both have small populations relative to the other markets in this study; Alberta has higher price volatility, and New Zealand has lower than average volatility. Australian markets show high EVOA, and two of them have low UVOA. One outstanding question is whether price velocity reduces as a market matures, in particular, in a post Enron era, will volatility of power price in North America decrease?

The same information on weekdays and weekends is shown in Section 3.8.4. On weekends, only Alberta and PJM show significantly higher unexpected price

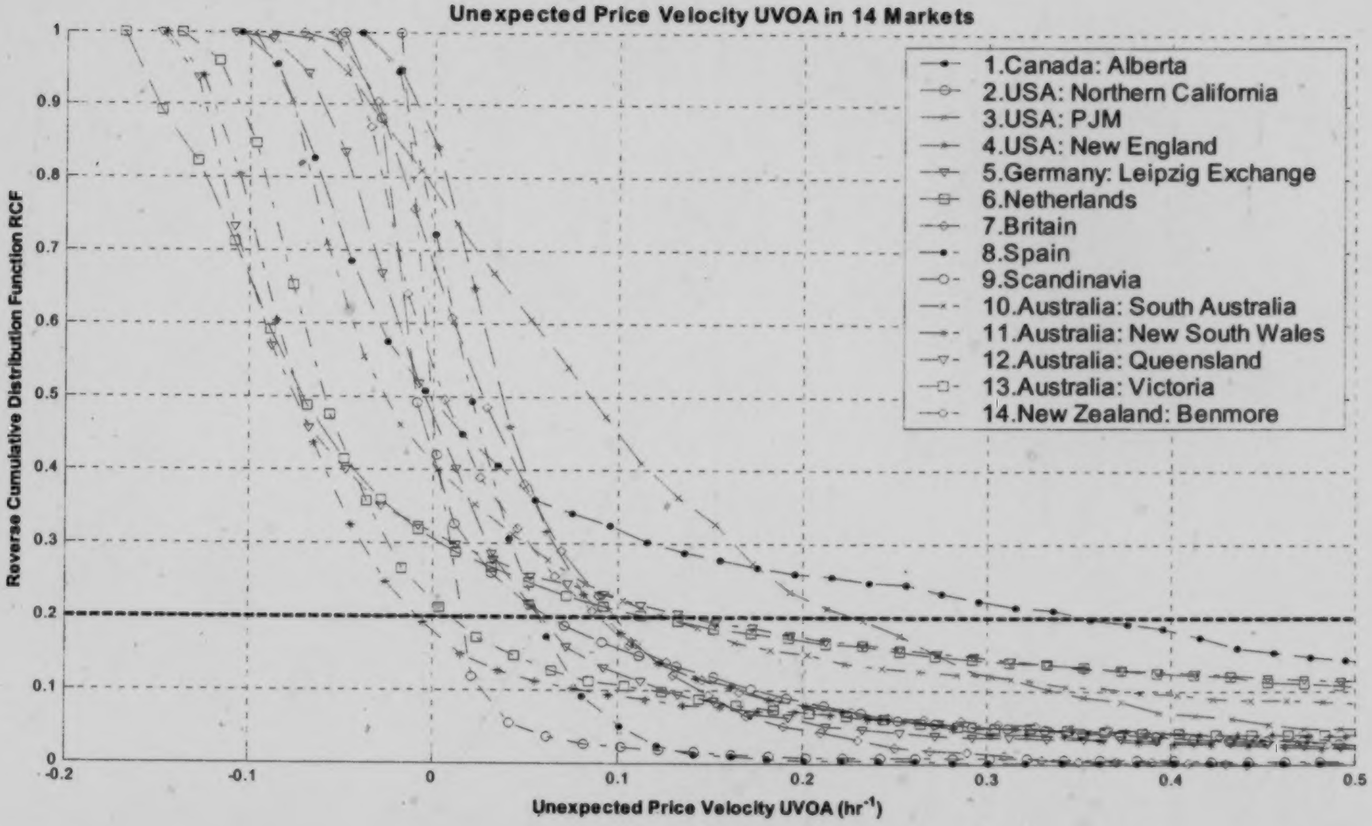

Figure 3-3 Reverse Cumulative Distribution Function (RCF) of Unexpected Price Velocity UVOA for 14 Markets.

velocity, thus the difference in expected price velocity between markets comes more from weekdays than from weekends.

3.5 Relationship between Volatility and Prices

Comparing trends in DVDA, the normalized price velocity relative to the average price on a given day, to trends in the normalized average price on that day, i.e., DAP, allows a comparison between markets of the "burstiness", or tendency to cluster, of periods of high price velocity and of high price. Figure 3-4 shows this comparison in four selected markets. Note that the range for the axes is different for each market; price velocity in Britain would appear substantially lower than the other three markets if plotted on a common axis. Also note that the choice of the range on the vertical Normalized Daily Average Price axis removed 4 points from California and 18 points from South Australia. Similar plots for the other ten markets are shown in Section 3.8.5. Figure 3-5 shows the correlation between DVDA and daily average price and load for all the 14 markets. Several observations emerge from an inspection of Figures 3-4 and 3-5:

- Price and volatility are "bursty", i.e., clustered, in some but not all markets. Alberta, for example, has a large cluster of high price from days 160 to 360 (i.e., from May to December 2000). California shows three periods of higher velocity, each corresponding to high power demand in summer. Note, however, that clustering is not evident in South Australia, and the occurrence of high price and high price change appears more random. Mount (1999) noted that despite broad ownership of generation, power prices in Australia are erratic.

- As noted, the annual periodicity in California is evident in volatility but not price, while in Britain the annual periodicity is evident in price but not volatility. No obvious periodicity is evident in South Australia.

- There is no consistent correlation between DVDA and the daily average power price or load, i.e., periods of high prices correlate to periods of high volatility in some but not all markets. For example, in New South Wales there is a high correlation, but the correlation is negative in Spain, and negligible in New Zealand, Scandinavia, and Northern California.

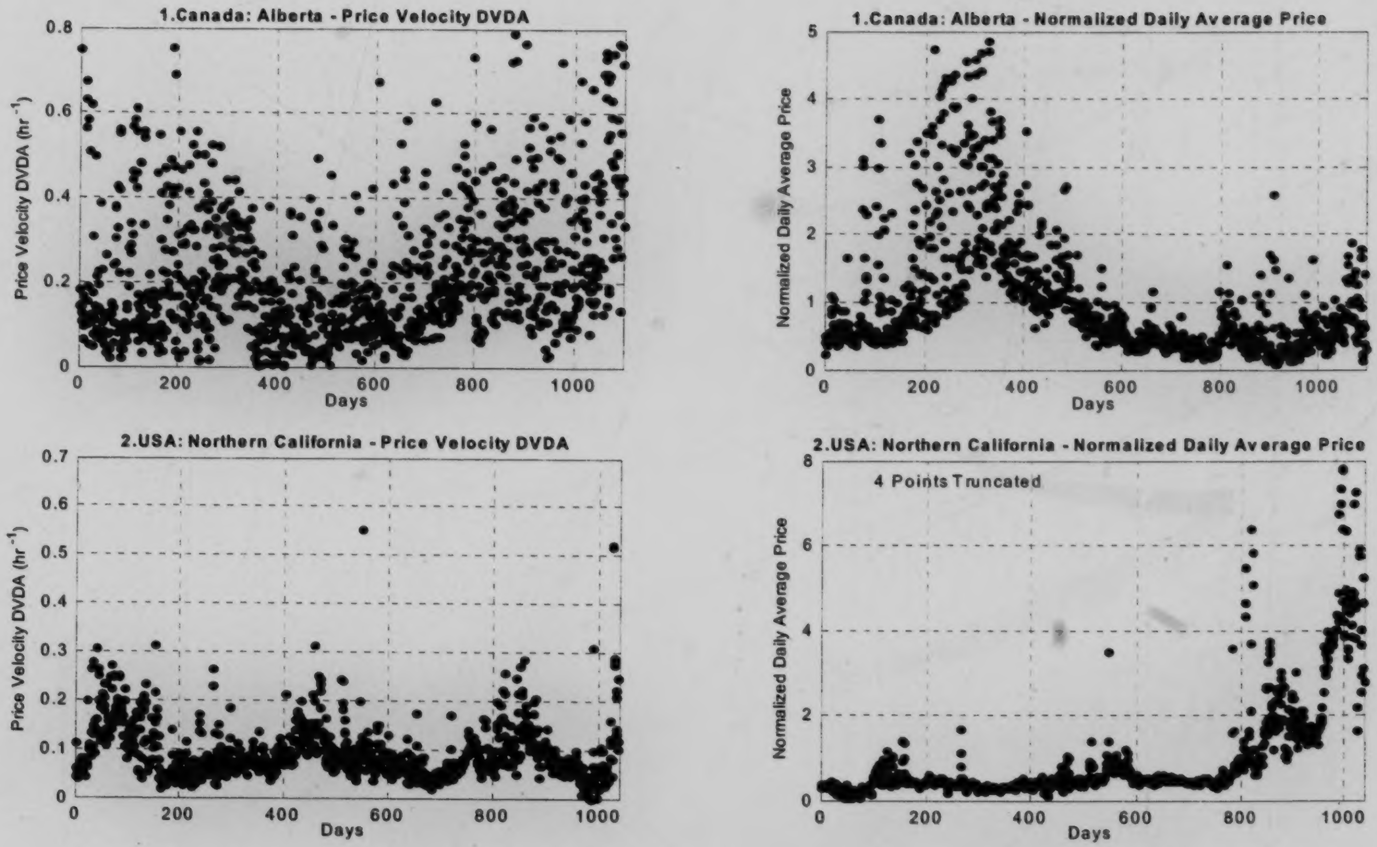

Figure 3-4 Price Velocity DVDA and Normalized Daily Average Prices for Four Selected Markets.

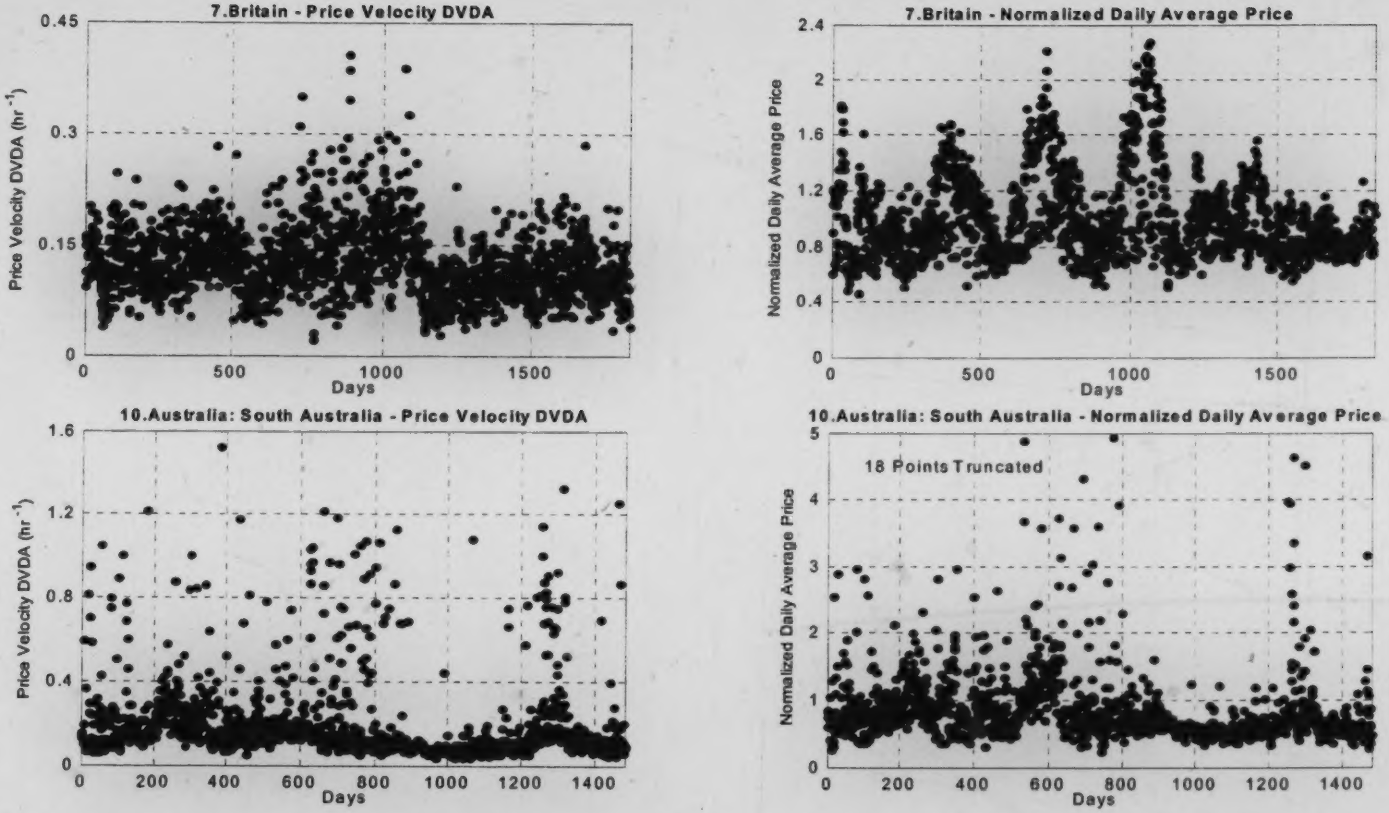

Figure 3-4 Price Velocity DVDA and Normalized Daily Average Prices for Four Selected Markets (Continued).

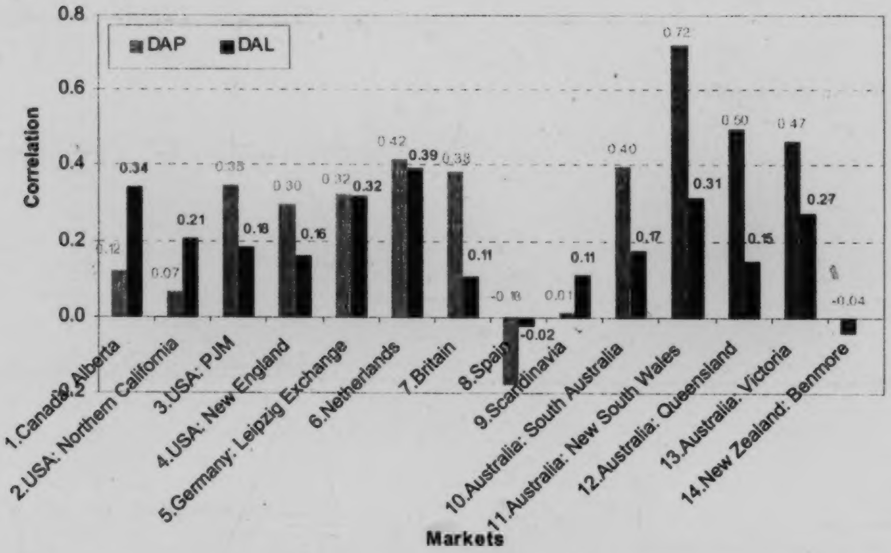

Figure 3-5 Correlations between Price Velocity DVDA and Daily Average Price, and between Price Velocity and Daily Average Load.

- DVDA has a higher correlation to price than to load in all but three markets: Alberta, California, and Leipzig.

From the perspective of power consumers, significant differences between deregulated power markets can be observed: Britain, for example, has predictable price patterns, as discussed in the precious work (Chapter 2; Li and Flynn, 2004), and relatively stable volatility, while South Australia has no clear pattern or consistency in either.

3.6 Some Reflections on Power Price Variability

Electrical power markets contain a great deal of short-term information, which in an ideal world would guide some actions by consumers as well as generators. In actual power markets it is dubious that significant responses to short-term price changes are being acted on by the majority of consumers.

Two reasons for this are technical: most consumers of electrical power have no knowledge of the price of power at any given hour or half-hour, and most meters for small and medium power consumers do not record the time at which power is used. Hence, the retailing of power to small and medium sized users is usually based on a flat rate. A third reason that short term price changes often do not affect power consumption patterns is that hedging mechanisms are available that allow customers to lock in fixed pricing. For very large consumers, hedging contracts may reflect time of use consumption and pricing, but for small and medium customers hedging mechanisms usually fix a price that is constant over one or more years and is independent of time of day. Hence, practically all small and medium consumers are shielded from time of use due to metering equipment, and hedged small, medium and large consumers are shielded over a longer period from changes in average power price. In deregulated power markets, a great deal of hourly or half-hourly price data simply does not impact the majority of consumers in a way that they can or need respond to, although markets with high and unexpected price variability generate concern in consumers and an erosion of support/tolerance for deregulation.

In a perfect world, all power consumers would know the hourly or half-hourly power price, and to the extent that they were capable, would make some adjustment in their behavior; RTP would create an incentive for this. Consumers in the Netherlands, which has the highest diurnal variation in average power price, would then find a strong incentive to use a home appliance such as an electrical dryer in the early hours of the morning, by having a timed start. Industrial operations that were high consumers of power, such as electric arc welding, would schedule their work to concentrate power usage in the same time frame.

However, as this study makes clear, the ability of a consumer to make sense of price patterns in deregulated markets varies strongly between markets. Britain, Spain and Scandinavia are examples of markets with low unexpected velocity. In contrast, Alberta and South Australia show high-unexpected velocity, and customers in these markets are justifiably on guard against unexplained and unexpected price spikes and periods of high hourly price change. The previous chapter demonstrated that Britain, Spain and Scandinavia have more consistent diurnal patterns of price, and a greater correlation between price and load. A consumer would be far more inclined to shape consumption behavior in Britain

Spain, and Scandinavia, while facing the market through RTP, and would be more likely to hedge in order to be indifferent to time of use in Alberta and South Australia. One interesting future comparison between deregulated markets would be the extent and form of hedging that is selected by consumers, to test if this can be related to the predictability of power price.

3.7 Conclusions

All of the power markets in this study are industrialized countries with high per capita GDP's. Despite this common economic base, price movement in deregulated power markets, measured in this work by price velocity, shows significant differences between markets. Some price velocity arises because of an expected diurnal pattern of price change, and some is unexpected. Deregulated power markets differ widely in the amount of unexpected price velocity, i.e., the average price change per hour that is not attributable to expected daily price patterns. Markets also differ in both the "burstiness" and periodicity of price level and volatility, and the extent to which high volatility correlates with high price. Deregulated power markets differ in their "consumer friendliness", i.e., the extent to which price patterns are comprehensible and periods of high-unexpected price movement are rare.

3.8 Additional Data of Price Volatility

3.8.1 Definition of Price Velocity

Mathematically, for each market, the following notations are used:

N : the number of days in the corresponding time period,
i : the index of day, generally $1 = 1, 2, .., N$,
M : the number of time periods during one day; for hourly power prices M *is 24* and for half-hourly power prices M is 48,
j : the index of time period, generally $1 = 1, 2, .., M$,
$p_{i,j}$: the power price at the *j-th* time period in the *i-th* day,
$DVDA_i$: the daily average price velocity on the i-th day referenced to the daily average price on the *i-th* day,

DVOA$_i$: the daily average price velocity on the i-th day referenced to the overall average price in the market.

The absolute price change at the *j-th* time period on the *i-th* day is described as,

$$\Delta p_{i,j} = \left| p_{i,j} - p_{i,j-1} \right|, \; i = 1, 2, \ldots, N; \; j = 1, 2, \ldots, M,$$

where $p_{i,0}$ is the power price at the M-th time period in the previous day, and $p_{0,0}$ is the initial power price in the given period which commonly is the last price in the day right before the given period. Averaging the price changes in a day, an average daily price change is calculated as,

$$\Delta \overline{p}_{i,\bullet} = \frac{1}{M} \sum_{j=1}^{M} \Delta p_{i,j} \, , \; i = 1, 2, \ldots, N.$$

Dividing this value by the daily average price DAP and the overall average price OAP, respectively, the two price velocities, $DVDA_i$ and $DVOA_i$ on the *i-th* day can be estimated,

$$DVDA_i = \frac{\Delta \overline{p}_{i,\bullet}}{\overline{p}_{i,\bullet}} = \frac{1}{M \times \overline{p}_{i,\bullet}} \sum_{j=1}^{M} \Delta \overline{p}_{i,j} \, , \; i = 1, 2, .., N, \text{ and,}$$

$$DVOA_i = \frac{\Delta \overline{p}_{i,\bullet}}{\overline{p}_{\bullet,\bullet}} = \frac{1}{M \times \overline{p}_{\bullet,\bullet}} \sum_{j=1}^{M} \Delta \overline{p}_{i,j} \, , \; i = 1, 2, .., N,$$

where $\overline{p}_{i,\bullet}$ is the DAP on the i-th day and $\overline{p}_{\bullet,\bullet}$ is the OAP in the studied period in the market,

$$\overline{p}_{i,\bullet} = \frac{1}{M} \sum_{j=1}^{M} p_{i,j} \, , \; i = 1, 2, .., N,$$

$$\overline{p}_{\bullet,\bullet} = \frac{1}{M \times N} \sum_{i=1}^{N} \sum_{j=1}^{M} p_{i,j} \, .$$

The unit for each velocity is hr^{-1}. As a currency-free measure, the daily price velocity, especially DVOA, allows a comparison of relative price movements between different markets.

3.8.2 Price Velocity of Weekend and Overall Prices

Table 3-5 Fraction of Days for Which Weekend Price Velocity DVOA and DVDA Exceed 0.1hr^{-1}, 0.2 hr^{-1}, and 0.5 hr^{-1}

Market	Fraction of Days (%)					
	DVOA (hr^{-1})			DVDA (hr^{-1})		
	>0.1	>0.2	>0.5	>0.1	>0.2	>0.5
9:Scandinavia	2.68	0.93	0.38	2.46	0.66	0.05
8:Spain	29.29	1.23	0.08	24.62	0.84	0.00
4:USA: New England	31.87	10.87	2.61	49.32	9.61	0.73
7:Britain	49.16	11.79	0.00	63.55	4.29	0.00
14:New Zealand: Benmore	32.28	11.88	3.48	39.86	13.12	2.05
11:Australia: New South Wales	35.38	12.20	4.92	51.84	10.12	3.50
2:USA: Northern California	22.54	12.28	3.51	32.93	5.26	0.40
13:Australia: Victoria	34.72	12.58	5.30	52.89	10.03	3.50
5:Germany: Leipzig Exchange	64.71	15.69	4.07	66.82	10.71	0.30
10:Australia: South Australia	42.48	23.37	9.93	58.94	24.60	7.47
12:Australia: Queensland	42.48	27.91	14.29	56.20	32.36	9.93
6:Netherlands	49.57	30.43	16.38	68.51	37.87	6.91
1:Canada: Alberta	52.17	33.25	18.29	79.16	45.78	8.06
3:USA: PJM	81.10	43.51	6.64	94.59	54.65	1.74

Table 3-6 Fraction of Days for Which Overall Price Velocity DVOA and DVDA Exceed 0.1hr^{-1}, 0.2 hr^{-1}, and 0.5 hr^{-1}

Market	Fraction of Days (%)					
	DVOA (hr^{-1})			DVDA (hr^{-1})		
	>0.1	>0.2	>0.5	>0.1	>0.2	>0.5
9:Scandinavia	0.68	0.00	0.00	1.23	0.00	0.00
8:Spain	29.50	2.11	0.00	30.08	1.72	0.00
11:Australia: New South Wales	21.75	8.27	3.07	33.33	5.67	2.36
7:Britain	40.69	9.79	0.19	60.46	5.37	0.00
2:USA: Northern California	20.95	10.14	2.36	36.49	7.09	0.34
5:Germany: Leipzig Exchange	72.93	10.15	0.00	65.79	11.65	0.00
4:USA: New England	48.96	10.42	1.82	53.39	8.59	0.00
13:Australia: Victoria	29.31	10.64	2.36	46.57	6.15	0.95
14:New Zealand: Benmore	31.37	11.18	3.11	40.22	15.22	1.09
6:Netherlands	44.95	18.35	3.19	53.72	24.20	2.13
12:Australia: Queensland	32.15	20.33	8.98	37.35	23.64	7.80
10:Australia: South Australia	41.13	21.51	7.33	51.06	17.97	4.96
1:Canada: Alberta	47.13	28.03	15.61	67.20	38.54	6.37
3:USA: PJM	75.26	44.39	8.42	86.99	41.07	1.02

3.8.3 Definition of Expected and Unexpected Price Velocity

To evaluate the "expected component" of price velocity, for each market the average diurnal price pattern is used to calculate an expected velocity (EV). Price velocity will be equal to the EV if the power price on a given day follows its historical average diurnal pattern exactly. Similarly, relating EV to the OAP and the DAP, respectively, yields two relative expected components of price velocity: the expected daily price velocity based on the OAP (EVOA), and the expected daily price velocity based on the DAP (EVDA). Subtracting EVOA from DVOA produces the other component unexpected from the diurnal price pattern, which is referred to as an unexpected daily velocity of power price (UVOA). Similar to DVOA, UVOA is a daily value: a daily average of hourly price change (absolute value) minus the component that is expected from the average diurnal price pattern. EVDA can be obtained similarly as EVOA. Unexpected price velocity based on the DAP (UVDA) results from subtracting EVDA from DVDA.

Again, mathematically, for each market, the following notations are used:

EV : the expected price velocity in the market,

$EVDA_i$: the daily expected price velocity relative to the daily average price on the *i-th* day,

$EVOA_i$: the daily expected price velocity relative to the overall average price in the market,

$UVDA_i$: the daily unexpected price velocity on the i-th day relative to the daily average price on the *i-th* day,

$UVOA_i$: the daily unexpected price velocity on the i-th day relative to the overall average price in the market.

For each market the "expected component" of price velocity, EV, arising from the daily average price pattern is estimated as,

$$EV = \frac{1}{M}\sum_{j=1}^{M} \Delta\bar{p}_{\bullet,j},$$

where $\Delta\bar{p}_{\bullet,j}$ is an hourly average price change calculated as,

$$\Delta\bar{p}_{\bullet,j} = \frac{1}{N}\sum_{i=1}^{N}\Delta p_{i,j}\text{ , } j = 1, 2, .., M.$$

Dividing this value by the DAP $\bar{p}_{i,\bullet}$ and the OAP $\bar{p}_{\bullet,\bullet}$, two values of EV, EVDA and EVOA can be obtained,

$$EVDA_i = \frac{EV}{\bar{p}_{i,\bullet}} = \frac{1}{M \times \bar{p}_{i,\bullet}}\sum_{j=1}^{M}\Delta\bar{p}_{\bullet,j}\text{ , } i = 1, 2, .., N\text{, and,}$$

$$EVOA = \frac{EV}{\bar{p}_{\bullet,\bullet}} = \frac{1}{M \times \bar{p}_{\bullet,\bullet}}\sum_{j=1}^{M}\Delta\bar{p}_{\bullet,j}\text{ .}$$

Note that each market has only one value of either EV or EVOA, and each day in a market has one value of EVDA. Correspondingly, the two values of unexpected velocity, UVDA and UVOA, are defined as,

$$UVDA_i = DVDA_i - EVDA_i\text{, } i = 1, 2, .., N,$$

and,

$$UVOA_i = DVOA_i - EVOA\text{ , } i = 1, 2, .., N.$$

Substituting *EVDA* and *EVOA* to the above formulas then arrives,

$$UVDA_i = \frac{\Delta\bar{p}_{i,\bullet}}{\bar{p}_{i,\bullet}} - \frac{EV}{\bar{p}_{i,\bullet}} = \frac{\Delta\bar{p}_{i,\bullet} - EV}{\bar{p}_{i,\bullet}} = \frac{\sum_{j=1}^{M}(\Delta p_{i,j} - \Delta\bar{p}_{\bullet,j})}{M \times \Delta\bar{p}_{i,\bullet}}\text{, } i = 1, 2, .., N,$$

and,

$$UVOA_i = \frac{\Delta\bar{p}_{i,\bullet}}{\bar{p}_{\bullet,\bullet}} - \frac{EV}{\bar{p}_{\bullet,\bullet}} = \frac{\Delta\bar{p}_{i,\bullet} - EV}{\bar{p}_{\bullet,\bullet}} = \frac{\sum_{j=1}^{M}(\Delta p_{i,j} - \Delta\bar{p}_{\bullet,j})}{M \times \Delta\bar{p}_{\bullet,\bullet}}\text{, } i = 1, 2, .., N.$$

Note that either UVDA and UVOA can have a negative value, which would occur on a day in which the actual price velocity is less than that expected from the average diurnal pattern of price. Unexpected price velocity is an indication of the level of risk, which the future will not turn out the way as expected.

3.8.4 Expected Price Velocity and Unexpected Price Velocity

Table 3-7 Weekday Expected Price Velocity EVOA and Unexpected Price Velocity UVOA that Is Exceeded on 10%, 20% and 30% of Days

Market	EVOA (hr^{-1})	UVOA (hr^{-1}), Fraction of Days		
		>30%	>20%	>10%
11:Australia: New South Wales	0.16	-0.03	0.01	0.11
13:Australia: Victoria	0.16	-0.03	0.01	0.13
9:Scandinavia	0.02	0.02	0.02	0.04
5:Germany: Leipzig Exchange	0.14	0.03	0.05	0.13
8:Spain	0.06	0.04	0.06	0.08
2:USA: Northern California	0.05	0.03	0.07	0.17
4:USA: New England	0.07	0.07	0.09	0.17
14:New Zealand: Benmore	0.06	0.06	0.10	0.18
7:Britain	0.09	0.07	0.11	0.15
10:Australia: South Australia	0.13	0.05	0.13	0.39
6:Netherlands	0.19	0.03	0.19	0.55
12:Australia: Queensland	0.14	0.04	0.20	0.72
3:USA: PJM	0.12	0.15	0.23	0.33
1:Canada: Alberta	0.11	0.15	0.37	0.63

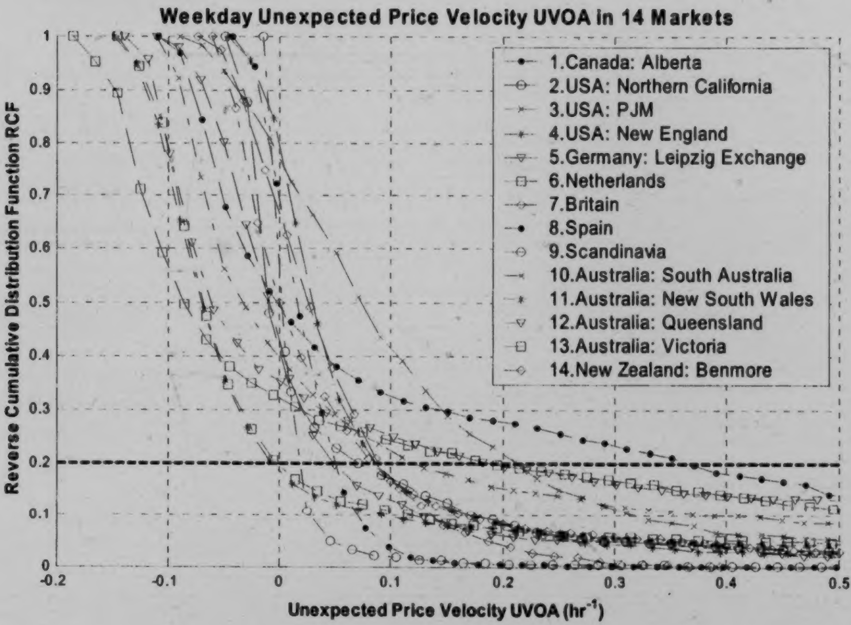

Figure 3-6 Reverse Cumulative Distribution Function (RCF) of Weekday Unexpected Price Velocity UVOA for 14 Markets.

Table 3-8 Weekend Expected Price Velocity EVOA and Unexpected Price Velocity UVOA that Is Exceeded on 10%, 20% and 30% of Days

Market	EVOA (hr^{-1})	UVOA (hr^{-1}), Fraction of Days		
		>30%	>20%	>10%
11:Australia: New South Wales	0.18	-0.07	-0.05	0.01
12:Australia: Queensland	0.21	-0.08	0.02	0.24
13:Australia: Victoria	0.12	-0.01	0.03	0.11
9:Scandinavia	0.02	0.03	0.03	0.03
2:USA: Northern California	0.06	0.02	0.06	0.16
5:Germany: Leipzig Exchange	0.11	0.06	0.08	0.12
8:Spain	0.06	0.04	0.08	0.10
10:Australia: South Australia	0.13	0.03	0.09	0.23
7:Britain	0.08	0.06	0.10	0.14
6:Netherlands	0.10	0.06	0.10	0.20
4:USA: New England	0.06	0.08	0.10	0.16
14:New Zealand: Benmore	0.05	0.07	0.11	0.17
1:Canada: Alberta	0.11	0.07	0.23	0.55
3:USA: PJM	0.09	0.19	0.25	0.37

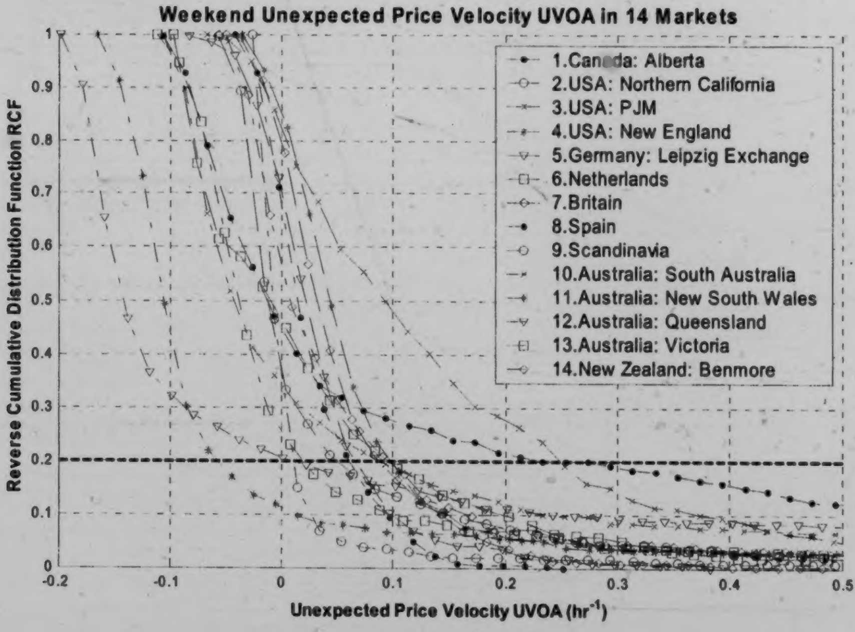

Figure 3-7 Reverse Cumulative Distribution Function (RCF) of Weekend Unexpected Price Velocity UVOA for 14 Markets.

3.8.5 Price Velocity and Normalized Daily Average Prices

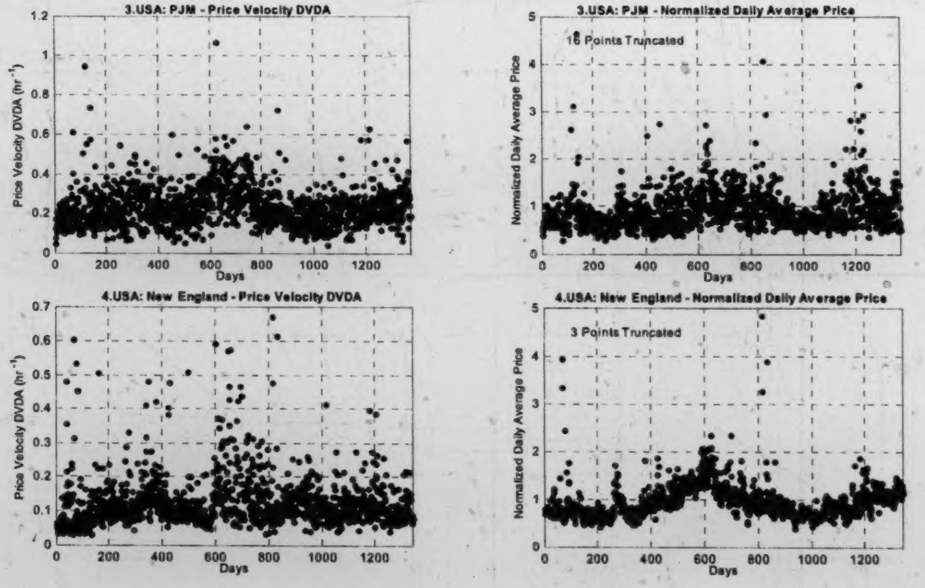

Figure 3-8 Price Velocity DVDA and Normalized Daily Average Prices for Two Markets in the U.S.

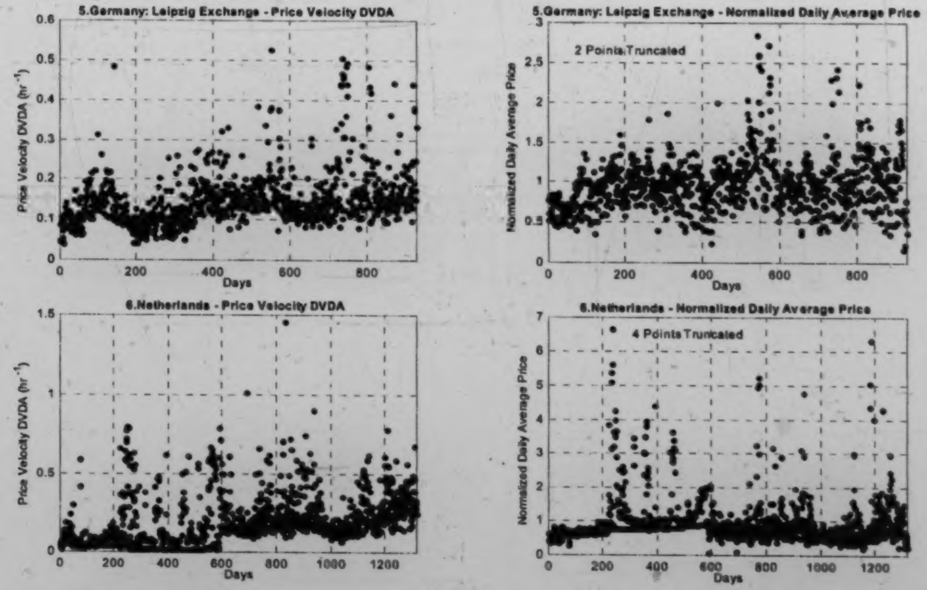

Figure 3-9 Price Velocity DVDA and Normalized Daily Average Prices for Four Markets in Europe.

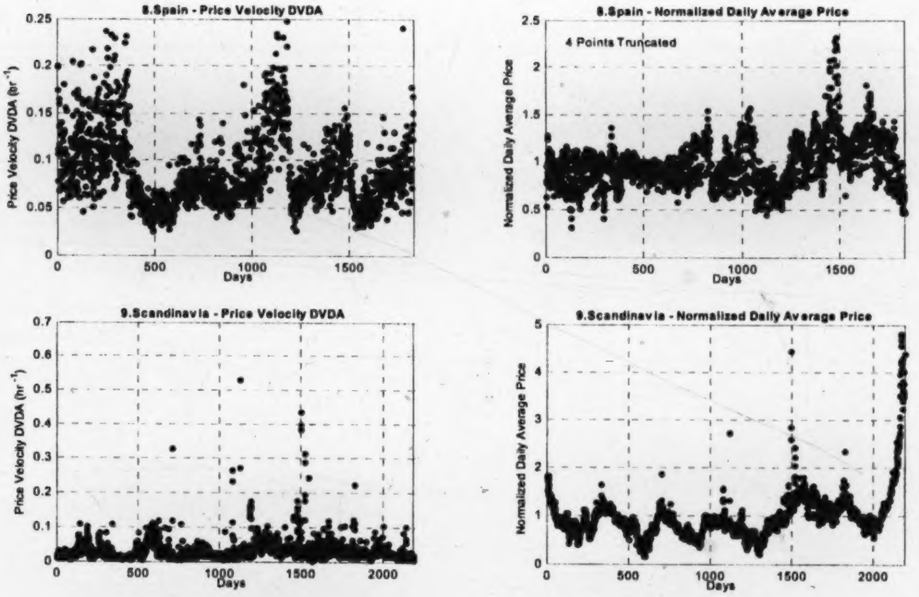

Figure 3-9 Price Velocity DVDA and Normalized Daily Average Prices for Four Markets in Europe (Continued).

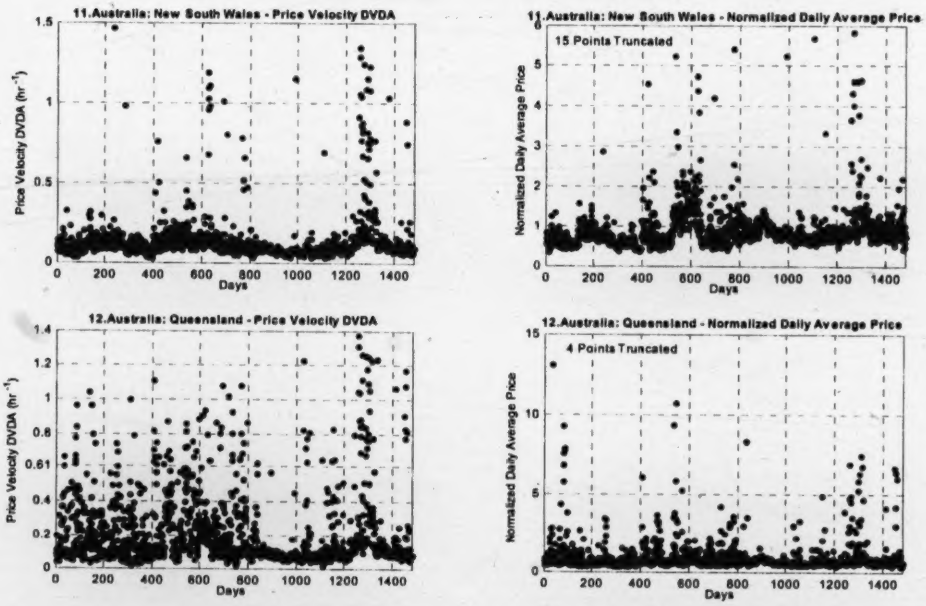

Figure 3-10 Price Velocity DVDA and Normalized Daily Average Prices for Four Markets in Oceania.

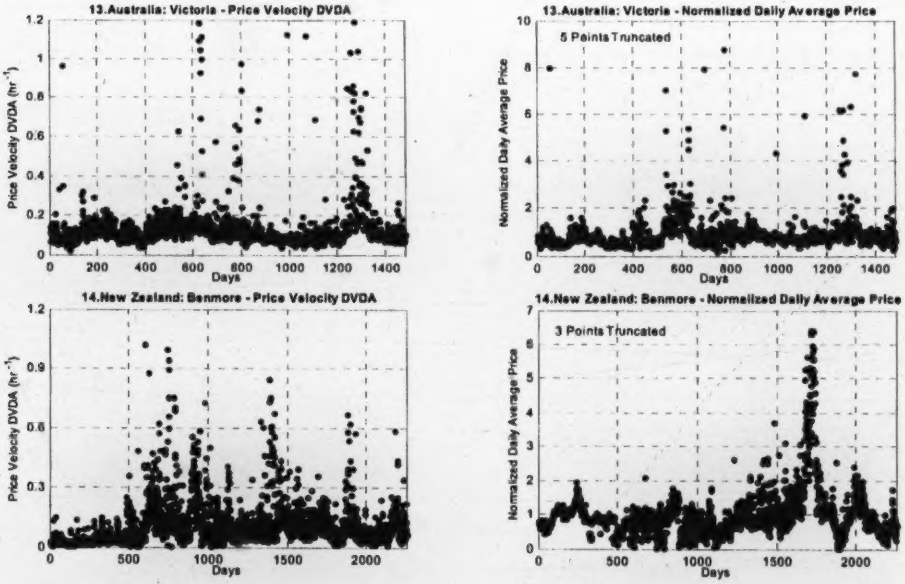

Figure 3-10 Price Velocity DVDA and Normalized Daily Average Prices for Four Markets in Oceania (Continued).

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CHAPTER 4 POWER PRICE CHANGES OVER TIME

Chapter 2 and 3 investigated the variances in power price, in particular the diurnal price patterns and the price volatility. One outstanding question is whether price variance changes over time in a deregulated market. The changes in power price patterns over time are examined in this chapter by looking at diurnal pattern and volatility changes over time in individual markets. Again the question to address is "can a thoughtful consumer facing RTP reasonably respond to price signals in the market by DSM?"

4.1 Introduction

Electrical power is not storable in significant quantities, and supply must equal demand over very short time intervals. Electrical power is generated from a variety of sources, with different operating and cost characteristics. The combination of these two factors gives a high degree of volatility and inter and intraday price change. Electrical power, unlike oil or natural gas, is also not transportable between remote markets, which allows the price of this fundamental energy commodity to vary independently. For example, a price excursion in Australia cannot be influenced by a surplus of power in other locations around the globe.

In previous work (Chapters 2 and 3; Li and Flynn, 2004a and 2004b) the author has assessed long-term average diurnal patterns and price volatility in the 14 deregulated power markets. Differences between deregulated power markets are significant. In this chapter, the author looks at patterns in power price and volatility on a season by season and year by year basis within individual markets. Power price is normalized to the long term overall average price in each market, in order to look at patterns independent of overall price. The author then looks at the diurnal pattern of average weekday price (AWDDP) and average weekend price (AWEDP) on an hour by hour or half hour by half hour basis, by season and by year. Winter is defined as December 1 through February 28 in northern hemisphere, and June 1 through August 31 in the southern hemisphere. (Note that the winter period in the northern hemisphere and summer period in the southern hemisphere is attributed to the year in which January and February occur, e.g. December 2000 and January and February of 2001 are referred to as Winter 2001 in northern hemisphere.) Other seasons are similarly defined as three calendar month periods. Seasonal and yearly changes are observed in diurnal power prices that are different between markets. (Details of the seasonal analysis approach are described in Appendix E. Data is summarized in Table 4-1. For details on the methodology of data "cleaning", and for specific references to each market, see Chapter 2 and Appendix B); data cleaning is not a significant source of error in the results.)

Table 4-1 Power Price Data for Deregulated Markets

Market	**Data Type**	**Time Period**	**No. of Data Points**	**% of Data Cleaned (%)**
1.Canada: Alberta	hourly	2000/01/01~2002/11/30	26304	0.03
2.USA: Northern California	hourly	1998/04/01~2001/01/31	24888	0.73
3.USA: PJM	hourly	1999/04/01~2002/11/30	32904	0.02
4.USA: New England	hourly	1999/05/01~2002/11/30	32184	1.05
5.Germany: Leipzig Exchange	hourly	2000/06/16~2002/11/30	22296	0.09
6.Netherlands	hourly	1999/12/1~2002/11/30	31584	0.25
7.Britain	half-hourly	1996/01/01~1997/12/31, 1998/03/01~2001/2/28	87696	0.08
8.Spain	hourly	1998/01/01~2002/11/30	43824	0.02
9.Scandinavia	hourly	1997/05/04~2002/11/30	52584	0.02
10.Australia: South Australia	half-hourly	1998/12/13~2002/11/30	53520	0.03
11.Australia: New South Wales	half-hourly	1998/12/13~2002/11/30	53520	0.03
12.Australia: Queensland	half-hourly	1998/12/13~2002/11/30	53520	0.04
13.Australia: Victoria	half-hourly	1998/12/13~2002/11/30	53520	0.03
14.New Zealand: Benmore	half-hourly	1996/11/01~2002/11/30	108096	0.04

The focus is from the perspective of power consumers: can some thoughtful consumers reasonably respond to price information in the market in order to implement DSM? (For a general discussion of DSM and the value of having at least some power consumers respond to price signals, see, for example, Caves *et al.* (2000), Hirst (2001), Borenstein (2002), and Kirschen (2003). Having some price responsive demand to moderate price spikes is noted, and Borenstein (2002) cites low DSM as a factor in the power crisis in California.) DSM can be thought of as occurring in two stages. The first, which is called easy load in this research, is power consumption that requires little advanced notice, thought or planning to interrupt; when the price is high, this kind of load is shut off. This first stage of DSM typically comes from large consumers and is available in any market. The greater the tendency of a market to experience high price spikes, the more vigorous the search for easy load. Beyond easy load is a second stage of DSM that requires more sophisticated planning, for example, of production processes, discussed by Kirschen (2003); it is called planned load in this research. This second level of DSM is only realizable in markets where consumers believe that planning can have an expected positive outcome. The less comprehensible and consistent power price patterns are, the less likely that second stage DSM will emerge.

The concept of price velocity is used to measure hourly volatility in power price. Some change in hourly power price will arise from the average diurnal pattern characteristic of that market. In addition to this component of price change that is expected from the average diurnal price pattern, some unexpected change can occur due to a variety of factors, e.g. weather or unit outages. For each day, the author calculates hourly price movement and subtract the "expected" component that would occur if power price exactly followed the average diurnal pattern; this residual component is called the unexpected price velocity. One can then normalize the unexpected price velocity to either that day's average price or to the long term average price in the market, and compute the daily average of unexpected price velocity. The resulting value is the unexpected price velocity relative to the daily average price (UVDA) or long term overall average price (UVOA). It measures the average hourly change in price on a given day relative to average power price. Each day will have a unique UVDA and UVOA; the distribution characterizes the volatility of the price in a given market. Details of the derivation of UVDA and UVOA are given in Section 3.8.3, Chapter 3. Note that an unexpected average hourly price change of $30 per MWh on a day with an average price of $300 per MWh and of $5 per MWh on a day with an average price of $50 per MWh would have the same value of UVDA.

The author chooses price velocity rather than variance as a measure of volatility because the author believes a consumer can better relate to this: what is the price change, and how fast does it occur, are concepts that consumers apply to volatile commodities.

In this chapter the author focuses on UVDA, because the author is looking at periods of price abnormality in markets. UVDA gives a sense of the consumer's perception of price volatility on a given day in the market relative to price levels on that day. A high value of UVDA means that price is shifting rapidly over the course of that day, while a low value means that price is following the pattern predicted from the history of diurnal prices within the market, regardless of the average price on that day.

Unexpected price velocity in part indicates the ability of a power consumer to manage power consumption. Small commercial and residential consumers have limited ability to implement DSM today because they do not have real time meters and a practical indication of real time price, and consequently cannot face the power market through spot (real time) pricing. Larger size commercial and industrial consumers (who generally have an ability to know the real time pricing and the time of use, for instance in Alberta,) can, if they choose, buy power at spot wholesale prices plus a premium for transmission and distribution; in this work, the author focuses on this aspect of DSM, i.e. real time pricing of power through direct purchase from the power pool. However, these consumers have very limited capability to respond on an hour by hour basis. Most industrial work is scheduled one or more days in advance, and legislation prevents sending a workforce home without pay on a few minutes notice. Hence whether power price patterns are relatively stable and whether price excursions can be related to comprehensible events such as weather excursions are important considerations for consumers in assessing their benefit from DSM.

Note that many people (for instance, Kirschen, 2003; Borenstein et al, 2002) have noted how critical DSM based on RTP (i.e. wholesale spot pricing with a transmission and distribution surcharge) is to improved functioning of deregulated power markets. The purchase of some power at spot price coupled with a reduction in consumption at times of high price is a critical element of DSM. It is not necessary that all consumers apply DSM through RTP, only that a sufficient number do so in order to have some reduction in demand in response to price spikes.

An analysis of diurnal price patterns and price velocity in the 14 deregulated markets season by season and year by year lead the author to categorize the markets into three groups: stable and consistent markets, markets with one bad period or season, and chaotic markets. The author discusses the implications of each, and in particular the author looks further at why deregulation of power has caused such a backlash in some markets. The author focuses on the history of deregulation in three markets (California, Alberta and Ontario), and considers policy issues that reduce the likelihood of a consumer backlash in markets considering deregulation in the future.

4.2 Time Patterns in Stable Markets

Figure 4-1 shows the seasonal price variations by year of AWDDP, AWEDP, and the reverse cumulative distribution function (RCF) of UVDA in Britain. (Note that UVDA can have negative values, when the price velocity is less than that expected from the long-term average diurnal pattern. All UVDA curves are truncated at a value of 0.5hr^{-1}, which eliminates a small number of values in the tail of the distribution.)

From the perspective of a power consumer who is considering planned DSM by modifying planed power consumption to reflect price, Britain is an example of a model market for deregulated power. There is a seasonal impact on power price patterns that is predictable and repeatable. Some price excursions occurred, for example, on weekdays in the winter of 1999, but these excursions were low enough to avoid a major backlash against deregulation by consumers. Previous work showed that there is a high correlation, about 0.7 between price and load; load in turn usually reflects weather extremes that can be forecast (Chapter 2; Li and Flynn, 2004a). Spain and Scandinavia (Nord Pool) have similar characteristics. (Seasonal price variations in these markets are shown in Section 4.7.1.) Spain had a period of slightly higher prices in the winter of 2002, and Nord Pool had periods of higher prices in 2001, but as with Britain in 1999, the deviation was not excessive, and volatility was low.

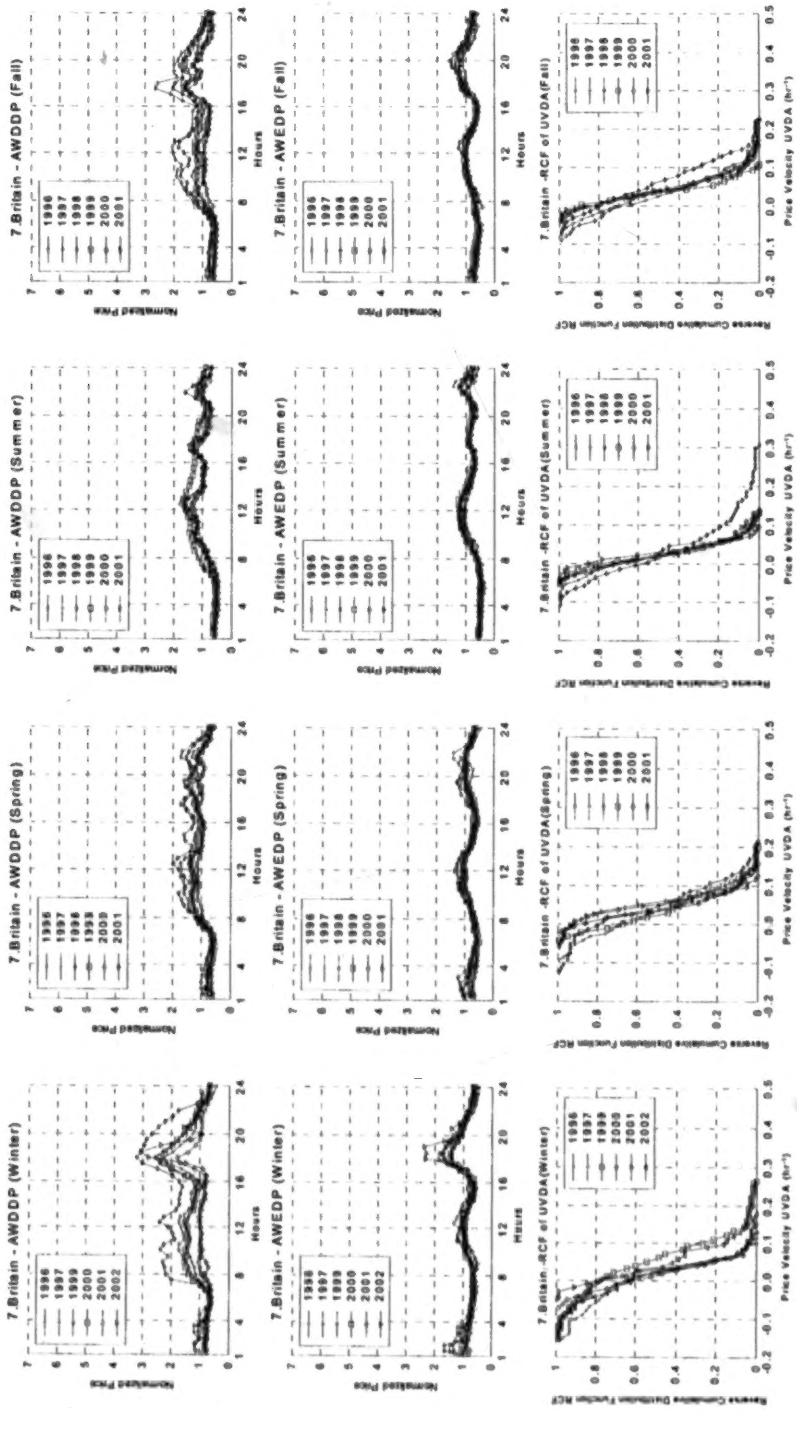

Figure 4-1 Seasonal Variations in Britain.

These markets are ideal from the power consumer's perspective; a thoughtful consumer of electrical power can reasonably manage demand by shaping consumption, because he can understand, and has confidence in, the consistency of price patterns in the market. The average unexpected hourly price change is low, less than 10%, and very rarely exceeds 20%.

The Leipzig Exchange (LPX), renamed the European Energy Exchange (EEX) in 2002, serves as more of a wholesale clearing market, and does not have enough history to draw comparable observations. (Seasonal price variations in the LPX are shown in Section 4.7.1.)

4.3 Time Patterns in Markets with One or Occasional Bad Price Periods

Figure 4-2 shows the seasonal price variations by year of AWDDP and AWEDP, and the reserve cumulative distribution of UVDA in Northern California. With the exception of a nine-month period from the summer of 2000 through the winter of 2001, California has had a stable and consistent power price. (For a discussion of the crisis in California, see, for example, Borenstein (2002) and Woo (2001).) However, the "one bad period" was so bad that it significantly reduced public support for deregulation; California's price spike got such prolonged media attention that the erosion of public support for deregulation extended far beyond California. By the winter of 2001 the average power price on weekdays in California was five times the long-term average price after deregulation, and ten times higher than previous winter prices.

This kind of price excursion overloaded the tolerance of consumers; and perhaps understandably so, since it was far higher than any price escalation in a basic energy commodity seen in the last 20 years. Political intervention in the power market was swift: California required power retailers to sell at fixed retail prices while buying wholesale from a market with no effective price cap, bringing several utilities into or near bankruptcy. It then re-entered the power market at the height of its price crisis, buying long-term power at very high prices. Many of these contracts were modified later based on the counterparty being judged to have inappropriately influenced the power market. California reduced the

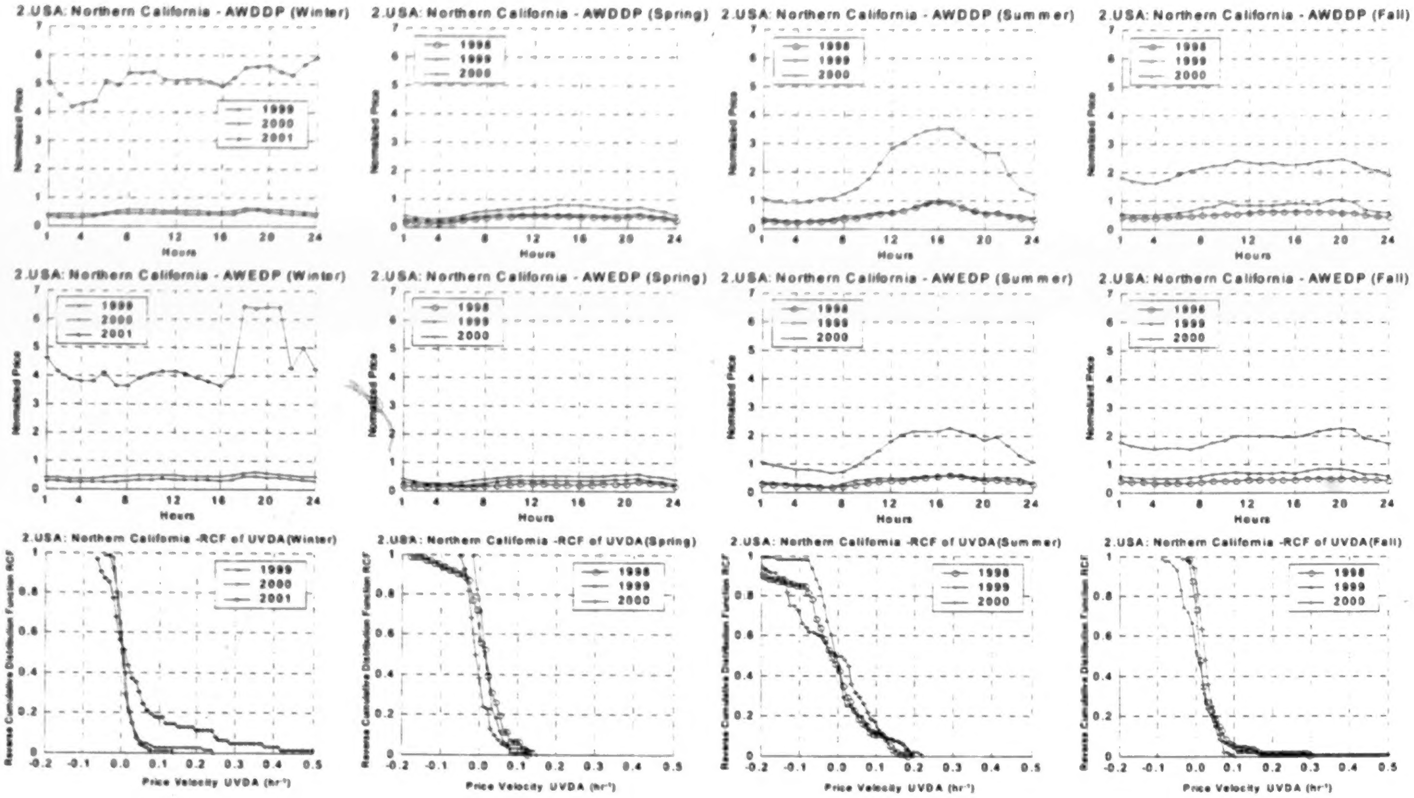

Figure 4-2 Seasonal Variations in Northern California.

appetite for deregulation in other states; various groups frequently propose a return to regulation. It is interesting to note that during the period of very high prices in the summer and fall of 2000, California did not have high volatility in price relative to the average price of the day. In the winter of 2001 unexpected price velocity was higher than in previous years, but not excessive compared to markets in Australia, discussed below. The problem in California was primarily high price, not high volatility.

Virtually the same observation can be made about the Province of Alberta, Canada, which experienced high prices in the same time period as California. Alberta's highest prices occurred in the fall of 2000, just before the residential and commercial markets experienced full deregulation. As a result, customers trying to buy power for the first time saw wholesale prices that were more than four times higher than long-term average prices. The consequences were similar, in that one period of very high prices has had a lingering impact on consumer resentment. As with California, there was an immediate political response: Alberta deferred a portion of power cost during the first year of deregulation into subsequent years, which had the impact of postponing the benefit to consumers when prices later retreated to more normal levels. While the current government in Alberta is committed to deregulation, re-regulation is proposed by opposition parties.

More recently, the Province of Ontario, Canada, first backed away from full deregulation of power because a pattern similar to Alberta had emerged: as the date of deregulation approached, power prices were spiking, and voter resistance became increasingly vocal. The first response was to cap residential and small consumer rates and support these from tax revenue. Then an election led to a change of government that announced it will re-regulate power.

New Zealand had one minor and one major bad period, as shown in Figure 4-3. The minor bad period occurred in the winter and spring of 2000, when weekday power prices showed high price spikes at two peak periods in the day. As expected, price velocity is higher during this time, arising from the rapid change in price over the course of the day. The major bad period occurred in the

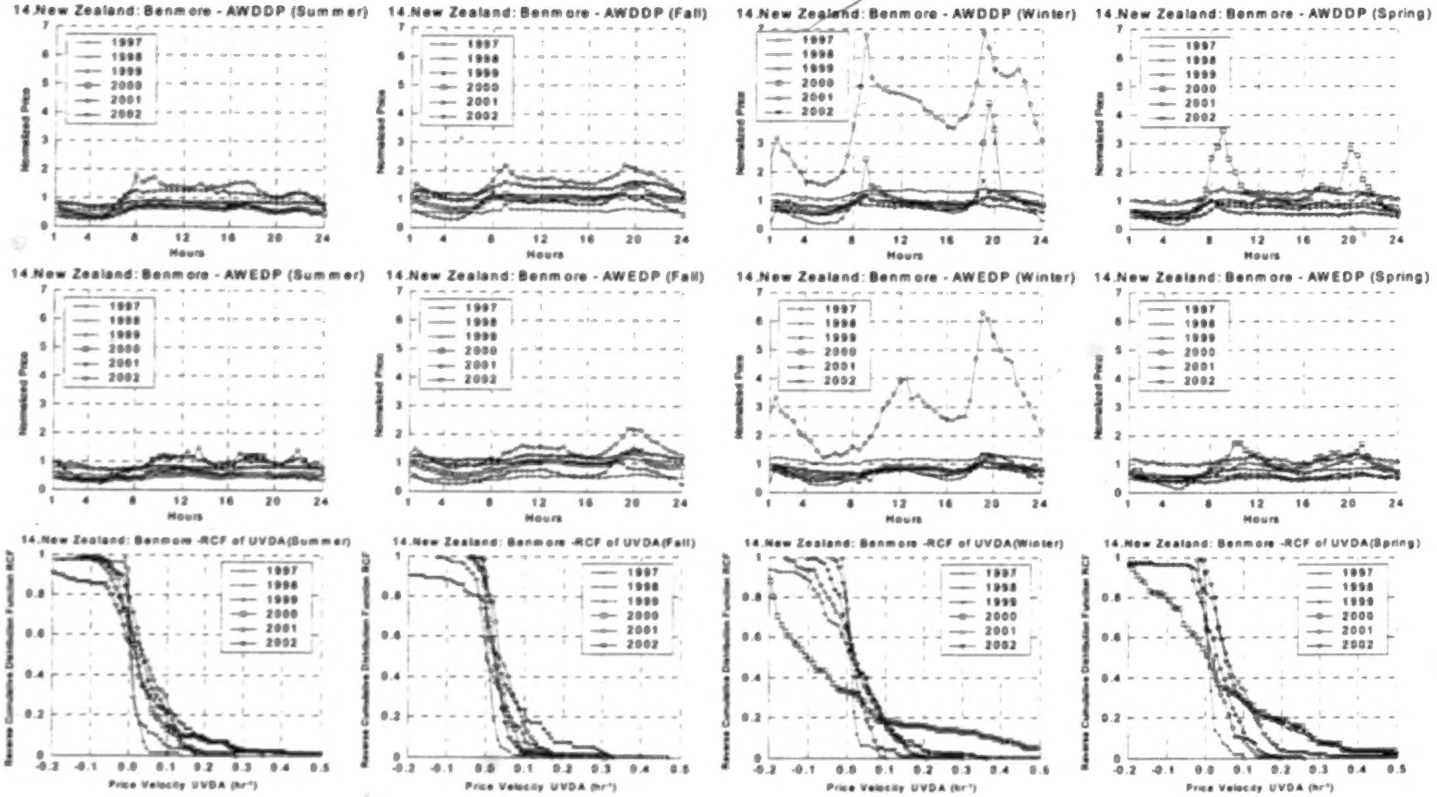

Figure 4-3 Seasonal Variations in New Zealand.

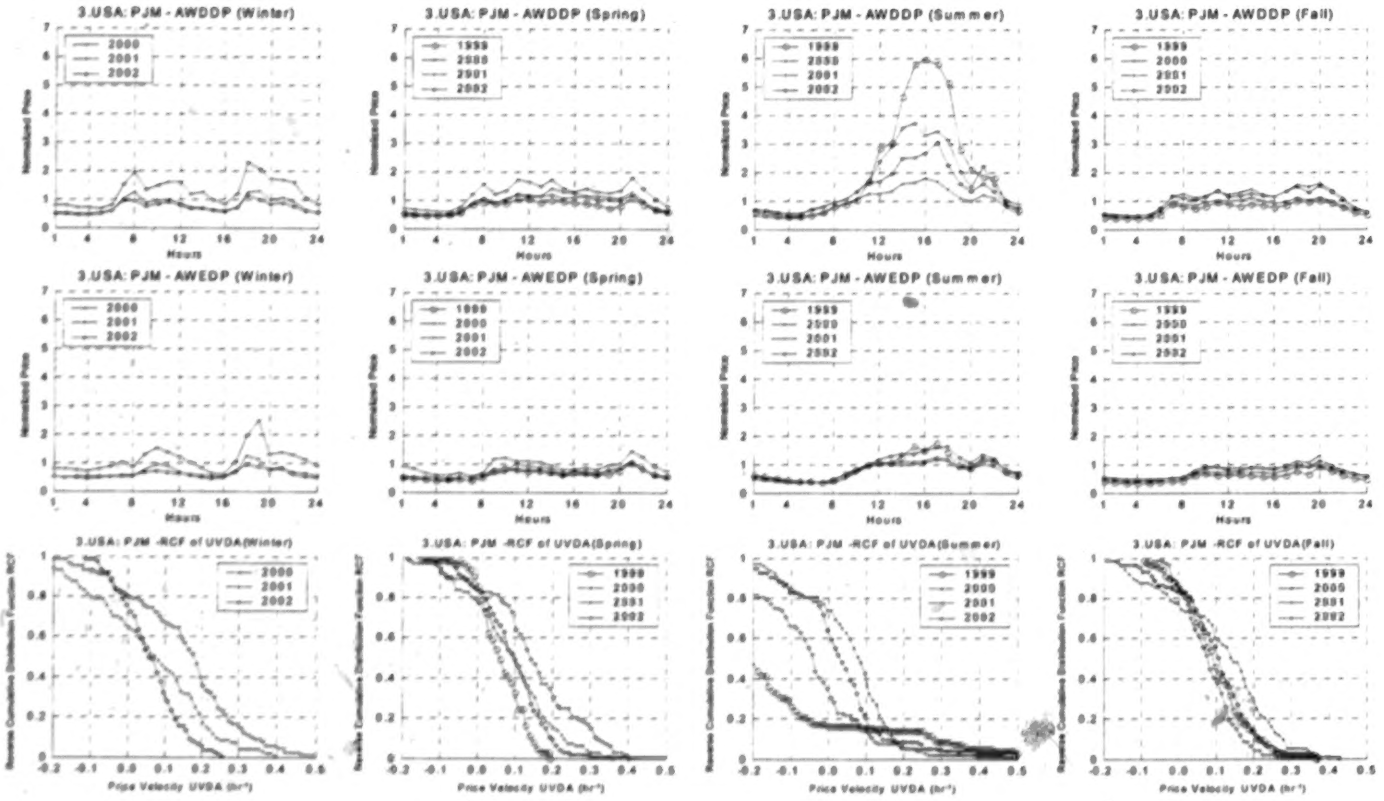

Figure 4-4 Seasonal Variations in PJM.

winter of 2001 and was caused by abnormally low rainfall that created a water shortage. This caused a long and severe period of high prices that were typically four or more times the long-term average price during peak usage hours on weekdays; the impact was felt on weekends as well. Power prices were high but not highly variable, relative to the average daily price, so unexpected volatility is actually lower in the winter of 2001 than 2000. As with other jurisdictions, the "one bad period" reopened debate about the merits of deregulation, although the duration and intensity of this has been less than that in California.

PJM in the eastern United States has a repeating bad season rather than "one bad period", as illustrated in Figure 4-4: power prices peak in the summer. Although the price spikes only occur on weekdays, they are presumably aggravated by the high power demand for air conditioning during this season. Volatility is also significantly higher in the summer. For the balance of seasons, PJM has been a fairly consistent market, with higher prices in the winter and spring of 2001 but not excessively so. The worst time of price excursion in PJM was in the summer of 1999, with prices peaking at more than six times the average price, but only for a few hours per day. Lower spikes in subsequent years have not generated the fierce reaction to deregulation that is observed in California.

Why have one or occasional bad periods stirred up strong public reaction in some markets while concern in other markets has been relatively muted? Table 4-2 shows the highest seasonal average weekday power price during a period

Table 4-2 Average Price during Excursions

Market	**Season with Highest Price Excursion**	**Normalized Average Weekday Price During the Excursion Period**
1. Canada: Alberta	Fall 2000	2.95
2. USA: Northern California	Winter 2000	5.14
3. USA: PJM	Summer 1999	2.13
4. USA: New England	Winter 2001	1.49
5. Germany: Leipzig Exchange	Winter 2002	1.61
6. Netherlands	Winter 2000	2.06
14. New Zealand: Benmore	Winter 2001	3.92

of high prices, and hence gives a sense of the sustained impact on the consumer over a three month period. (Seasonal price variations in Alberta, New England and the Netherlands are shown in Section 4.7.2) The author speculates that two factors must exist for prolonged widespread public frustration with deregulation of power: a period of very high price, and a cause that is not easily identified and attributable to an external "one time" event. Thus California and Alberta both had periods of very high price without a clearly identifiable weather related cause. New Zealand had the period of high price, but consumers could identify a "one time" cause and hence, perhaps, link high price to the need to conserve through an unusual and infrequent event. Because the period of high price in Alberta and California could not be related to an external weather event, fears of ongoing high price were more difficult to dispel, and there was a greater tendency to blame the market and greedy participants. Subsequent events in California, where a number of companies reached agreements with the U.S. Federal Energy Regulatory Commission (FERC) to make payments to settle claims of market manipulation, have only served to solidify consumers' biases.

Why have markets faced "one bad period"? One key reason is a shortage of supply. Markets that had abundant generation capacity at the time of deregulation and adequately functioning means to prevent strategic withholding fared well through deregulation, despite other issues of market design. Britain, Spain and Scandinavia are examples of this. Where there is adequate generation capacity and a well functioning market, no special measures appear to be required during deregulation to prevent periods of unusually high price.

One cause of a supply shortfall in some deregulating markets is that a period of low or no investment in new generation assets preceded the onset of deregulation. In both Alberta and Ontario there was a long gap between the announcement of a commitment to deregulation and the resolution of all of the complex rules and transition arrangements. In the case of Alberta, existing investors in regulated generation units received an ongoing stream of payments that kept them "whole" as if deregulation had not occurred, but the right to bid and dispatch power from these units was sold in an auction. The complexity of these arrangements took years to implement. During this period, investors were more hesitant than normal to invest in new generation assets until the rules were clarified. In California, existing generators were forced to sell generation units, which again had the impact of reducing new investment in power generation; California's formidable environmental hurdles also contributed to a long process for commissioning new generation (Woo, 2001). In Ontario, a single crown corporation owned the vast majority of generation and transmission and most rural distribution; breaking up this large entity and selling off some of the generation assets again took time. In these cases, the long process to deregulate helped ensure that after deregulation the markets would be vulnerable to price excursions because generation investment was retarded.

4.4 Time Patterns in Chaotic Markets

Figure 4-5 shows the seasonal price variations by year of AWDDP and AWEDP, and the reverse cumulative distribution of UVDA in South Australia; the patterns in Figure 4-5 are typical of all markets in Australia. (Seasonal price variations in other three Australian markets, New South Wales, Queensland, and Victoria are shown in Section 4.7.3)

Australian power markets have price patterns that are unlike any others in this study. Average prices show a number of price spikes in the diurnal pattern; previous chapter showed that these spikes are often created by prices on less than 5% of the total days (Chapter 2; Li and Flynn, 2004a). From Figure 4-5 it can be seen that many of these spikes are inconsistent from year to year and from season to season. It can be also seen that vast shifts in price volatility that again are inconsistent from year to year and season to season. For example, the spring and summer of 2001 (ending in February 2001) and the fall and winter of 2002 show very high price velocity relative to other years. There is no evidence of short-term price fluctuations damping out as the market matures. An earlier work (Chapters 2 and 3; Li and Flynn, 2004b) noted that price and load show a low correlation in Australian markets, so price cannot be linked back to high consumption related to weather extremes.

This pattern of prices has created a ready market for "easy load" DSM; the severity of the price spikes has led to a vigorous search for load that can be turned off without planning. However, the same price pattern would make it

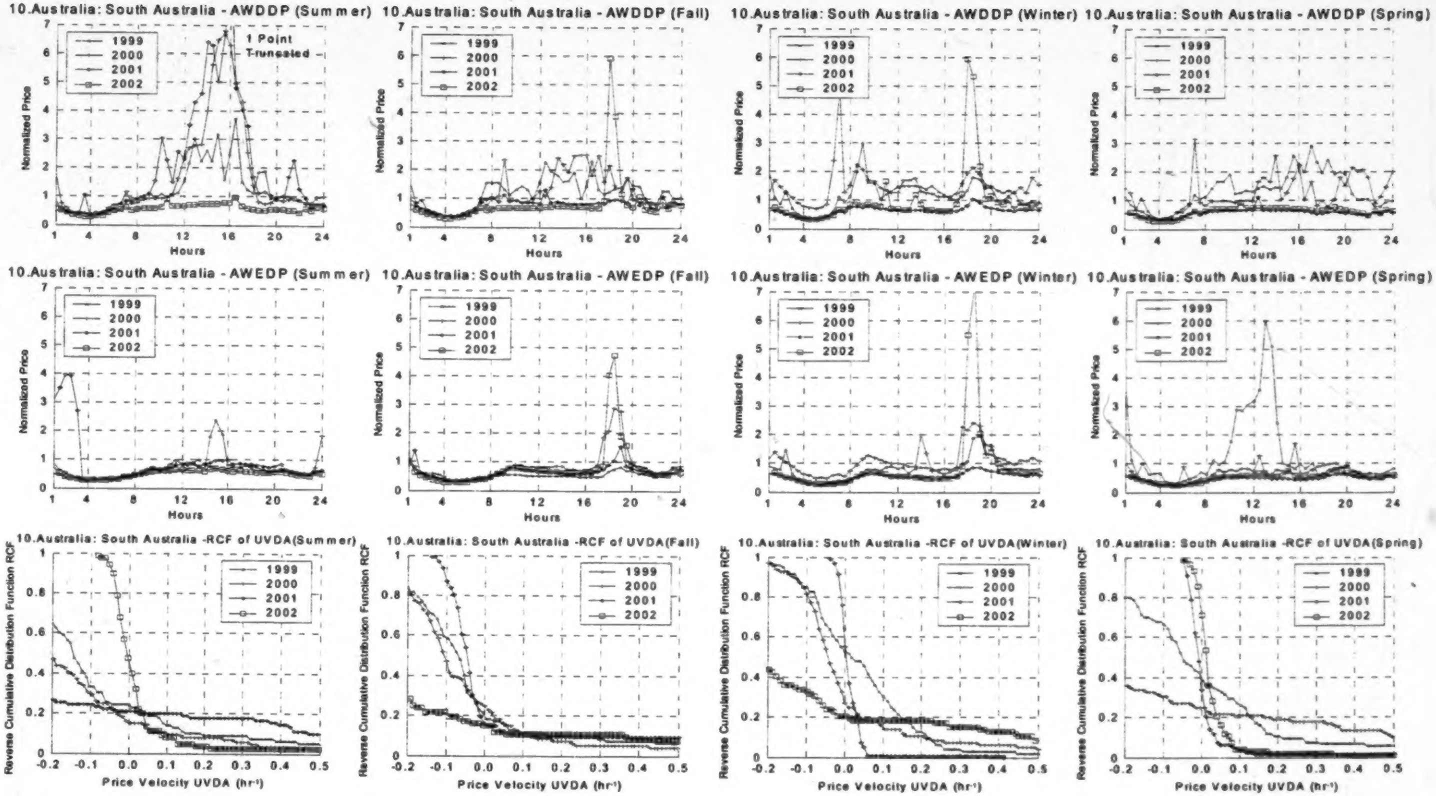

Figure 4-5 Seasonal Variations in South Australia.

virtually impossible for a consumer to implement a second stage of planned DSM as a price responsive strategy, since price changes cannot be associated with understandable causes. The author speculates that a significant power consumer in Australia would be far more likely to avoid price risk through hedging, compared to the same consumer in Britain, Spain or Scandinavia.

4.5 Discussion: Policy Implications

Several benefits can be attributed to deregulation of electrical power:

- Costs arising from the regulatory process are avoided.
- Competition occurs in new generation.
- Smaller power generation projects can be built that could not support the burden of the regulatory process but are economical without it.
- Price signals to consumers enable power consumption patterns to reflect the true cost of power, which varies over the course of the day, week, and season.

The first three act on generation, and the last on demand. All of these benefits can only be realized if political support remains in place for deregulation. In addition, the fourth benefit arises from DSM. DSM that proceeds beyond easy load is only realizable if price signals from the deregulated market are comprehensible to the consumer.

The history of public/political support for deregulation is mixed. California's experience put deregulation on hold in many jurisdictions around the world, as political support vanished in the face of understandable consumer fears. Re-regulation of the power market has been a political issue in each of Alberta and California, and deregulation was interrupted mid-stream in Ontario. The cause in each case was one "bad" period of very high price. Each of these markets has provided signals to the generation side, but the potential for re-regulation has reduced the effectiveness of those signals, very notably in Ontario. For signals to the demand side, there is a wide variation between deregulated markets. At one extreme, Britain would appear to have reaped all of the benefits of deregulation: a British power consumer who chooses to face the market through DSM can reasonably expect a reward, and there is no strong political backing to revert back to a regulated power industry. At the other extreme, Australia has price patterns that are so erratic that a consumer has little prospect of making sense of them.

One lesson from an analysis of power price patterns is that "one bad period" early in deregulation can damage public support for deregulation, sometimes fatally. From the analysis of markets that display "one bad period" in Section 4.3, the author thinks there are some practical policy considerations that can minimize the likelihood of "one bad period".

A. Focus on the surplus of generation capacity when contemplating deregulation.

   Jurisdictions that have record low generation reserve when they reach the point at which the small power consumer faces deregulated power price are inviting price spikes with the potential to create a political backlash against deregulation. Governments contemplating deregulation should carefully map out a timeline, including contingency for unexpected events, and use load forecasting tools to determine if there will be adequate generation reserve at the end of the process. If not, the government should contemplate steps to ensure that some generation capacity is built in the interim.

   There is clear evidence that generation investment will occur in a timely manner once deregulation is fully implemented; the shortfall in generation is a transitional effect. The author notes two further observations: generation capacity may not in itself ward off price spikes: in an earlier work the author noted a low correlation between price and load, particularly in Australia and Alberta which have relatively high price volatility (Chapter 2; Li and Flynn, 2004a). There is not yet sufficient knowledge of market behavior to separate physical issues from market design and market gaming issues. However, there is also some evidence that if a surplus of generation capacity exists at the time of full deregulation, then in some markets no further steps may need to be taken; Britain, Spain and Scandinavia illustrate this.

B. Reduce the time between the announcement of deregulation and its implementation to a minimum.

Deregulation has often been associated with early announcement of intent accompanied by sweeping initial statements of its benefits that often reflect the political orientation of the governing body implementing it. In reality, deregulation is profoundly complex to implement, because issues of how to fairly deal with formerly regulated units that were built in good faith by owners are complex to resolve. In addition, the issue of market power must be addressed, since frequently in a regulated market there is one or a few dominant players. Solutions have varied, as noted above. For example, California and Ontario mandated the sale of generation assets, while Alberta created a complex instrument called a Power Purchase Agreement that left title to formerly regulated units in the hands of their original owners, but gave the right to bid and dispatch power to a third party purchasers for the duration that each unit would have been regulated under the old regime. Even when a broad solution is identified, details take time to resolve.

During the delay between announcement and implementation of deregulation virtually no new generation is built due to market uncertainty. Continued growth in power demand during the period reduces the generation surplus that existed at the time of the announcement of deregulation. Long delay increases the risk of a generation shortfall. Achieving rapid implementation is difficult because of the complexity of the issues that must be addressed in deregulation, and the desirability of consultation with industry and consumer groups. However, a government contemplating deregulation could take steps to inform itself of the history (or experience) of deregulation in other jurisdictions, the decisions that will be required, and its own approach to deregulation so that the consultation process is expedited.

C. Contemplate wholesale price caps either throughout deregulation or during a transition period.

Price caps are a matter of some controversy in terms of impact on a market. From a theoretical perspective, they are resisted by economic purists, who argue that the market should remain unfettered by artificial limits in order to give a proper economic signal to trigger new investment. Stoft (2000 and 2003), for example, argued that price caps in California drove away potential suppliers and thus had the effect of increasing power price in the long term. Others (Huges and Parece, 2002; Niimura and Nakashima, 2001; and Robinson and Baniak, 2000) express a concern about the short term impact of price caps, in that suppliers will tend to drive the price towards the cap; the cap in effect becomes a target. Robinson and Baniak (2002) noted that volatility in Britain increased significantly during the period of a two year price cap, and Niimura and Nakashima (2001) note that the frequency of $250 per MWhr pricing in the California market increased notably when this became the price cap.

On the other hand, many jurisdictions (e.g. Alberta, California, and Australia) have put in price caps, in part to protect consumers since most do not know the price of power at the time of usage. There is also clear evidence of massive consumer resistance to high power prices, especially in the period just after the onset of deregulation. Consumer resistance has led to major market redesign in many jurisdictions, e.g. US markets, and to the termination of deregulation in Ontario. Power is unique from other energy commodities in that it cannot practically be stored and most consumers are unaware of its price at the time of consumption, not can their consumption be related to a particular point in time because of a lack of a time of use meter. The first of these factors prevents management of power price through inventory and timed purchase, and the second impairs DSM. Given this, the author believes that on balance governments contemplating deregulation could at least test the support for a price ceiling, to limit public resistance to deregulation.

The author believes that the argument that unfettered price excursions are necessary to trigger investment is somewhat dubious for extremely high price spikes. Most companies will, in looking to the expected future return on generation investment, discount extreme price spikes, since the spikes are presumed to be infrequent and construction of new generation units by themselves and others will further reduce the frequency. Hence, the author believes that a power price spike to 200 to 300 times normal value, as occurs in Australia, does not provide much of an incremental generation side investment signal relative to a lower cap (about 30 times in Alberta, for example), but is highly effective in creating demand side resistance to deregulation.

In summary, there is some evidence that low price caps, particularly in the presence of a "gaming" environment, will lead suppliers to target the price cap more often then they otherwise would do, distorting the market. On the other hand, no or very nigh price caps, particularly in the presence of a "gaming" environment, can lead to price excursions and volatility that in turn lead to a consumer/voter revolt, as occurred in Ontario. The author believes that moderate price caps, either permanent or for a transition period, would help to limit public resistance to deregulation.

D. Avoid retail price caps, or link them to wholesale price caps.

Retail price caps, which were instituted in each of California, Alberta, and Ontario, create a key problem: who will pay the difference between a set retail and unrestrained wholesale price. Although the answers were different for the three markets (shareholders in California, consumers in Alberta, and taxpayers in Ontario), each created problems. Wholesale price caps can moderate the impact of price excursions on consumers, but ultimately the consumer needs to pay the deregulated price.

4.6 Conclusions

Deregulated power markets have had different patterns of price history over time. The 14 markets in this study can be classified into stable, "one bad period" or season, and chaotic markets. Stable markets, as exemplified by Britain, Spain, and Scandinavia, have consistent seasonal price patterns and low levels of volatility in power price. Price excursions can be related to load, which in turn usually reflects extreme weather events. Consumers in such a market could reasonable face the power market through DSM. There is little backlash against deregulation in stable markets.

"One bad period" markets, as exemplified by California, Alberta, and New Zealand, generally have the characteristics of stable markets except for a period of high price. Alberta and California had extended periods of high price (more than 2.5 times overall average price) that were not clearly attributable to an external event such as drought or a major unit outage; in each market, there has been a backlash against deregulation. A similar period in New Zealand could be attributed to a rare weather event, and the backlash was not as severe.

Australian power markets have erratic price patterns and very high volatility that is not related to load or weather; the markets show high variation from year to year and season to season. Planned DSM would be difficult to impossible to achieve in these markets.

Jurisdictions considering deregulation in the future can consider four steps to reduce a backlash against deregulation:

- Focus on the surplus of generation capacity through the deregulation process, and if necessary take steps to insure it does not reach critically low levels.
- Reduce the time between the announcement of deregulation and its implementation, since in the interim there is a hesitancy to invest in generation.
- Contemplate wholesale price caps either throughout deregulation or during a transition period, to moderate the impact of price for a commodity that cannot be stored and for which, for many consumers, the price is unknown at the time of consumption.
- Avoid retail price caps, or link them to wholesale price caps, to avoid a catastrophic loss by players forced to buy at a floating price and sell at a lower fixed price.

4.7 Additional Data of Seasonal Price Variations

4.7.1 Stable Markets: Spain, Scandinavia and Leipzig Exchange

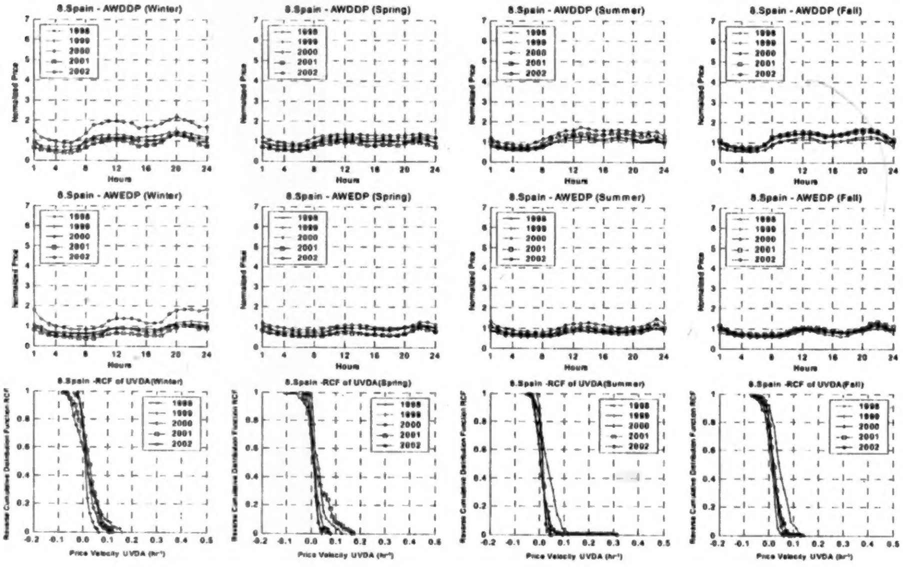

Figure 4-6 Seasonal Variations in Spain.

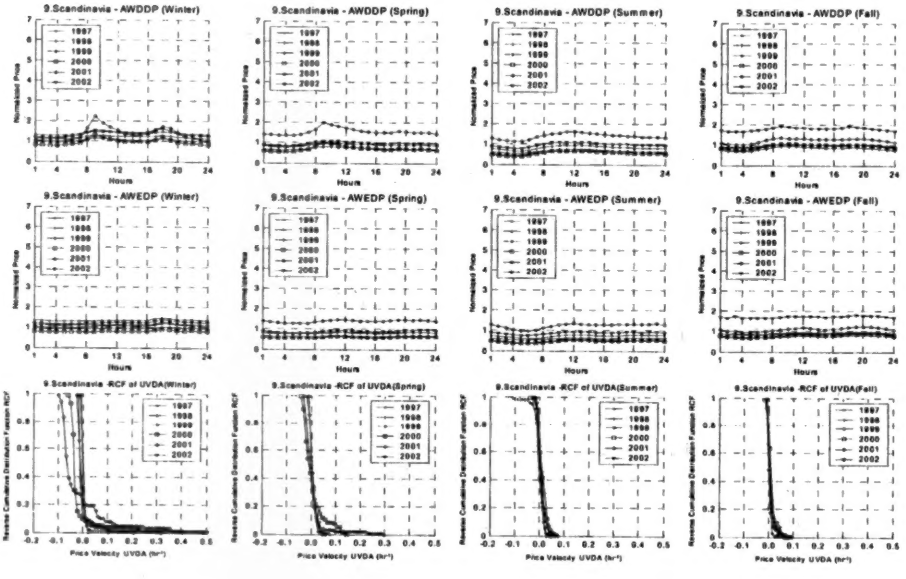

Figure 4-7 Seasonal Variations in Scandinavia.

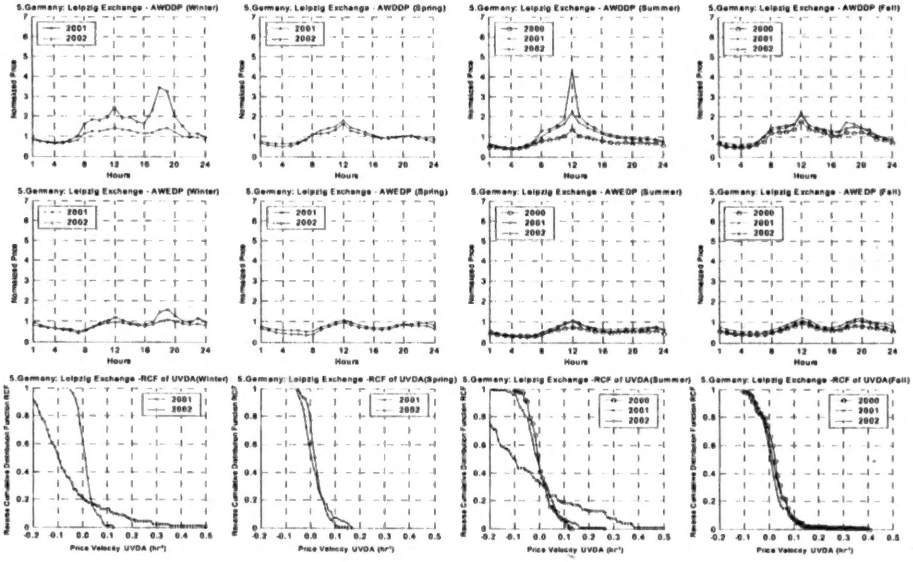

Figure 4-8 Seasonal Variations in Leipzig Exchange.

4.7.2 Markets with One or Occasional Bad Price Periods: Alberta, New England, and the Netherlands

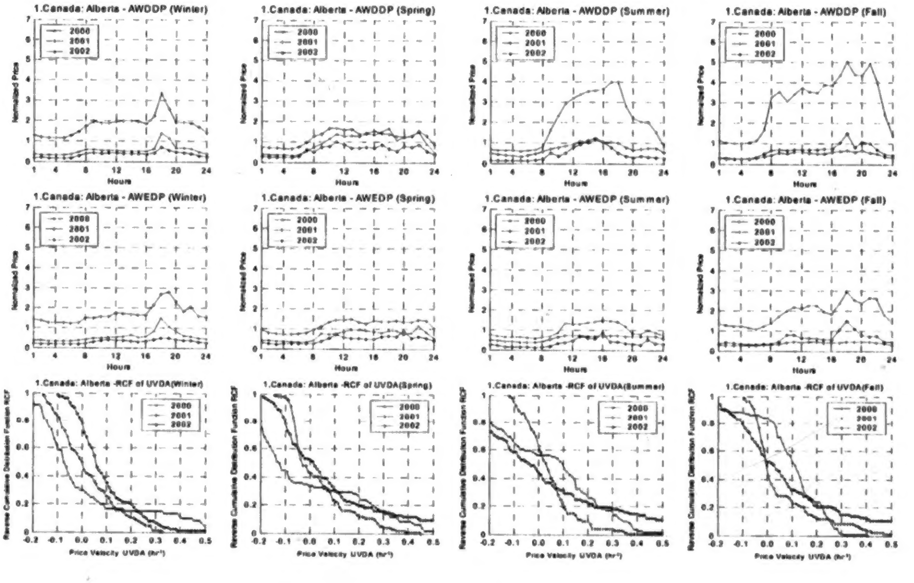

Figure 4-9 Seasonal Variations in Alberta.

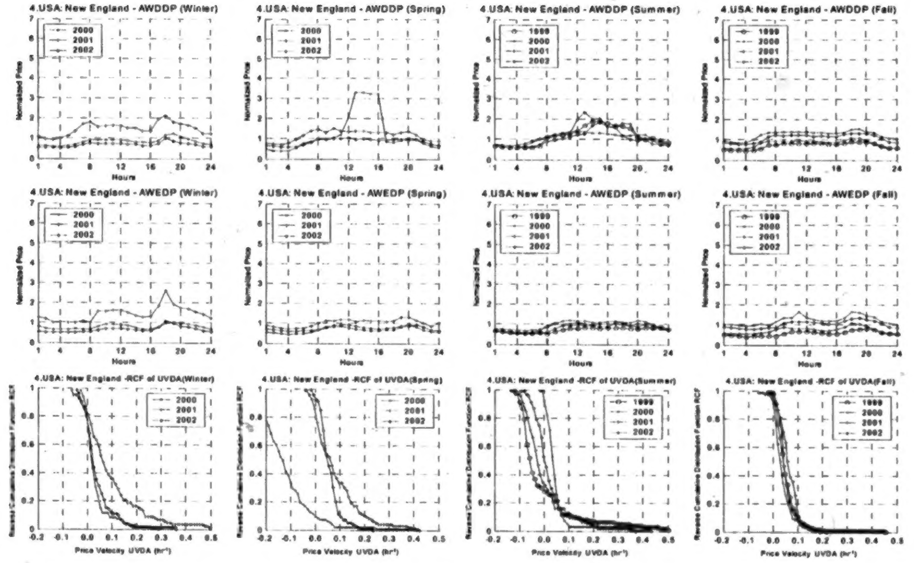

Figure 4-10 Seasonal Variations in New England.

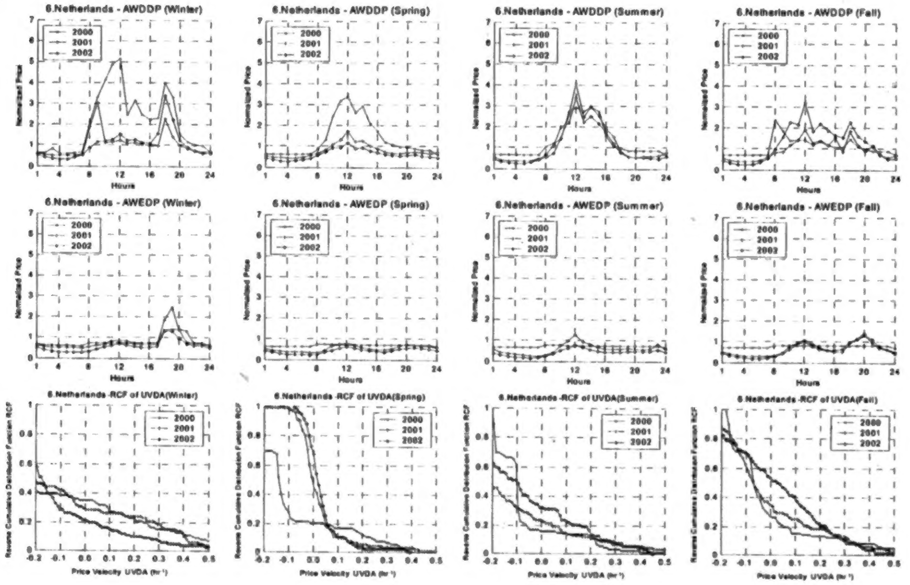

Figure 4-11 Seasonal Variations in Netherlands.

4.7.3 Chaotic Markets: Markets in Australia

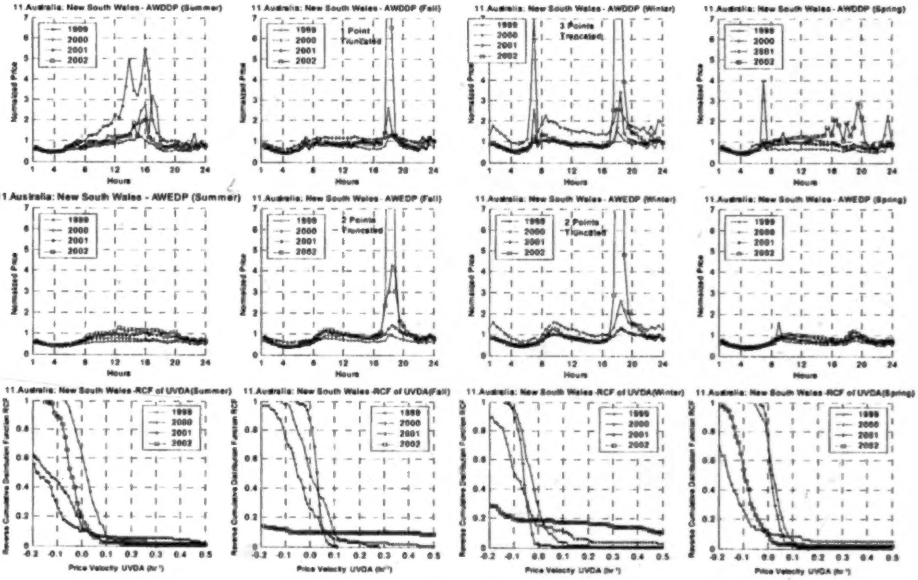

Figure 4-12 Seasonal Variations in New South Wales.

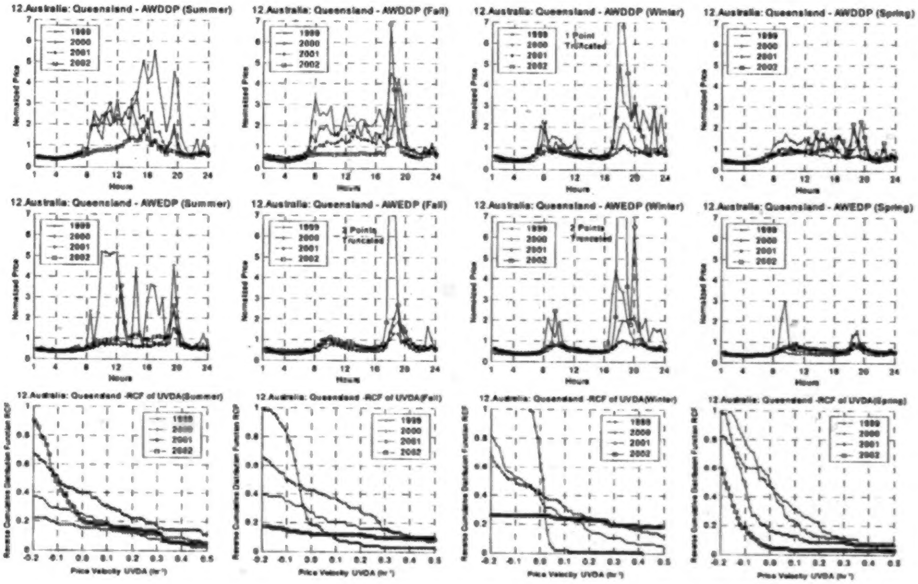

Figure 4-13 Seasonal Variations in New Queensland.

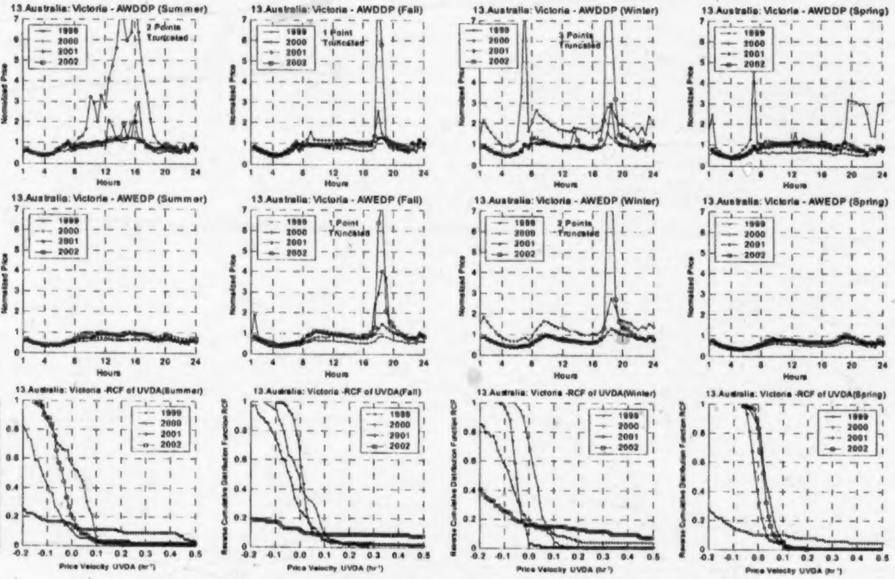

Figure 4-14 Seasonal Variations in Victoria.

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CHAPTER 5 DISCUSSION AND CONCLUSIONS

One prominent feature of the last two decades has been the change in the organizational structure of the electric power industry, which has been motivated by the combination of political, market, and technological influences. Both power consumers and power providers are beginning to face a higher level of financial risks. Providers are facing the risk that increasing competition may make their investments or contracts uneconomical, while consumers are being exposed to greater price risks when long-term contracts are replaced by short-term ones, or even by RTP. These changes give rise to spot and futures markets for electricity. Thus understanding power prices in the new deregulated competitive market settings has been playing an important role in understanding deregulated markets, especially from the perspective of market participants.

5.1 Discussion

The unique fact that electricity is not physically storable in significant amounts gives deregulated electricity markets that are characterized by highly volatile prices. All markets studied are in industrialized societies that share some common work patterns. For example, most people sleep in the early hours of the morning, and in all markets lower power usage and price in this time period can be seen. However, as this study revealed in Chapters 2, 3, and 4, the 14 studied deregulated markets differed significantly in terms of average price patterns, price volatility, and changes over time. Different sources and patterns of space heating may be one reason creating differences between markets. For example European price patterns may reflect more use of electricity based space heating at home, workplace, and retail outlets, perhaps coupled with a tendency to lower indoor temperatures to a greater extent during the night. However, the underlying reasons are unclear. Market structures (e.g. the generation mix, for example, how much power generation capacity comes from hydro, coal, natural gas or nuclear power), market design (e.g. biding strategy, hedging mechanism, whether the "pool" is mandatory for all power or a clearing market for a small fraction of power, and the extent and effectiveness of market surveillance) may contribute as well. Both technical and market factors contributing to differences in power price patterns are worthy topics of future research.

Deregulated power prices contain an abundance of short-term information (half hourly or hourly), which, in a perfect world, would serve as signals for power consumers who would adjust their consumption activities accordingly to reduce the cost for power. However, in reality the combined influence of lack of real time metering, limited knowledge of prices, and the existence of time insensitive hedging in some markets constrains the ability of power consumers to react to price signals and practice planned DSM. With RTP, planned DSM would help to moderate price variations, and thus mitigate markets risks. However as this study showed, planned DSM is not likely to be achievable in some markets. For example, informed power consumers in stable markets, e.g. Britain, Spain, or Scandinavia, should be more inclined to engage in planned DSM in response to RTP signals than the same consumers in chaotic markets, e.g. Australia, where the consumers would be more inclined to hedge to moderate the price risk. Power purchase decisions are also worth future research.

Deregulation began with an expectation of lower prices and better service in terms of more service packages for power consumers. Some experiences of deregulation, for example, in Britain or Scandinavia, are positive. However, other experiences of deregulation, for example, in California or Ontario, have not fully supported those expectations. In particular, after the 2000-2001 California electricity crisis and the collapse of the energy firm Enron, the impetus to deregulate slowed down, and deregulated markets in some jurisdictions are being actively redesigned (for example, Ott, 2002; Wolak, 2003). However, the exact way in which deregulation and competition manifests in the power industry varies based on local laws and regulations (Larsen and Bunn, 1999; Kiesling and Mannix, 2003, Ramos-Real, 2004), and there is no consistency in market designs. As revealed by this study, deregulated markets differ markedly in term of prices. There will be a need for each jurisdiction to adapt, e.g. combine existing models, or invent a model that is suitable for itself. Even the answer to whether deregulation is good or not is unclear yet (Steiner, 2001; Roach, 2003, Hattor and Tsutsui, 2004).

5.2 More Potential Future Research

One opportunity for further research to identify causes of differences in power price patterns between markets is an assessment of differences in consumption behaviors. For example, is the double peak pattern of load and price in European and Oceanic markets a product of different space heating sources and patterns, as speculated previously?

A decision to hedge reflects many things, including tolerance of risk. However, as this study makes clear, the driving force to hedge power prices is different between markets. Another opportunity for future research is whether highly volatile prices suppress DSM, i.e. is hedging chosen more often in high volatility markets than in low volatility markets.

Whether there is a correlation between any market design parameter and observed volatility is another opportunity for further research. One participant in the Australian power industry, who requested anonymity, speculated that a key factor in low volatility is a strong and effective market surveillance mechanism that quickly chastises behaviors such as strategic withholding of power. Research that includes a highly detailed understanding of the effectiveness of market intervention might shed light on this.

A fourth area of future research is to extend the kind of analysis done in this study to other deregulated markets. Deregulated power markets in South America, for example, were excluded from this study because of an inability to obtain price data. Were such data to be made available, these markets could be compared to the 14 in this study. In addition, markets in Asia are at the beginning stages of deregulation, and data will likely soon be available from them.

Finally, the ability to predict price, i.e. develop a valid model that can accurately forecast future price or price patterns, has been an area of past research, although with limited success (see, for example, Bastian et al., 1999; Szkuta *et al.*, 1999; Angelus, 2001). The comprehensive data set from this study can be used as an input to test power price forecasting models.

In the future policy decisions, for example, regulation of power generation technology, directly or indirectly, to reduce greenhouse gas impact, will have some impact on power price. This can be analyzed through techniques developed in this study.

As noted above, the belief that deregulation of electrical power is good is not universally held, and future research and dialogue will address this issue for many years to come.

5.3 Conclusions

Deregulated power markets strongly differ in their "consumer friendliness", i.e., the extent to which price diurnal patterns, price volatility, and price changes over time are comprehensible and periods of highly unexpected price movements are rare. The causes of these differences, as discussed above, are complex, and future research can help identify causes.

Deregulated power prices in different deregulated markets show fundamentally different patterns. North American markets show a consistent monotonic diurnal price pattern on weekdays, while all other markets show either morning and evening price peaks or choppy multiple peaks. Deregulated power prices differ between markets in the ratio of average maximum vs. average minimum price and the ratio of average weekday vs. average weekend price, which create the incentive to time shift power consuming activities. Deregulated markets also differ in the extent to which a small fraction of the total days shape the average price pattern and the value of hourly or half-hourly price. Deregulated markets show a wide variation in the correlation between load and price.

Price velocity, the average price change per hour over the course of a day, also varies vastly between deregulated markets. Some price velocity arises from an expected diurnal pattern of price changes, and some is unexpected. Deregulated power markets differ markedly in the unexpected price velocity, i.e., the average price change per hour that is not attributable to expected daily price patterns. Markets also differ in both the "burstiness" and periodicity of high volatility or prices, and the extent to which high volatility correlates with high prices.

Deregulated power markets have had different patterns of price history over time. The 14 deregulated markets in this study can be classified into stable, "one bad period" or season, and chaotic markets.

- Stable markets, as exemplified by Britain, Spain, and Scandinavia, have consistent seasonal price patterns and low levels of volatility in power prices. Price excursions can be related to load, which in turn usually reflects extreme weather or climate events. Consumers in such a market could reasonably face the power market through DSM. There is little backlash against deregulation in such stable markets.
- "One bad period" markets, as exemplified by California, Alberta, and New Zealand, generally have the characteristics of stable markets except for a period of high prices. Alberta and California had extended periods of high prices that were not clearly attributed to an external event such as drought or a major unit outage; in each market, there has been a public backlash against deregulation. A similar period in New Zealand could be attributed to a rare weather event, and the backlash was not as severe.
- Australian power markets have erratic price patterns and very high volatility that is not related to load or weather or climate; the markets show high variations from year to year and season to season. Planned DSM would be difficult to impossible to achieve in these markets.

From the perspective of the power consumer, in stable markets, e.g. Britain, Spain, or Scandinavia, a thoughtful consumer could reasonably face the market and engage in planned DSM in response to RTP signals. A decision, for example, to shift production to night or away from weather extremes could be expected to have a payoff. In contrast, in chaotic markets, e.g. Australia, the erratic price history makes planned DSM unlikely to be rewarded. A customer in these markets is justifiably on guard against unexplained and unexpected price spikes and periods of high price changes and in turn would be more likely to hedge in order to shield from the price risk. North American, Germany and New

Zealand markets are intermediate between the stable markets and the chaotic markets.

Jurisdictions considering deregulation in the future can consider four steps to increase the likelihood of success of, and to reduce a public backlash against, deregulation, including 1) focus on the surplus of generation capacity through the deregulation process, and, if necessary, take steps to insure it does not reach critically low levels; 2) reduce the time between the announcement of deregulation and its implementation to a minimum to mitigate the effect of the transition period, since in the transition period there is a hesitancy to invest in generation due to the uncertainness; 3) contemplate wholesale price caps either throughout deregulation or during a transition period to moderate the impact of price for a commodity that cannot be physically stored by the consumer in a significant amount and for which, for many consumers, the price is unknown at the time of consumption; and 4) avoid retail price caps, or at least link them to wholesale price caps, to avoid a catastrophic loss by players forced to buy at a floating price and sell at a lower fixed price.

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APPENDIX A THE ELECTRIC POWER INDUSTRY AND ITS DEREGULATION

It is hard to image a world without electricity. Economical and reliable supplies of electricity have made possible many of the services that we associate with modern life today. From lighting and cooking to television, telephone, and computing, electricity is a critical input supporting a wide range of consumption, transportation, and production activities. People rely on electricity so often and so easy that they just simply take it for granted. Our expectations even go much further than that. We expect the cost of consuming electricity to be reasonable and reliable. Easy and affordable accessibility to the electric transmission grid is considered essential. It is the relative stoppage of service, especially the prolonged blackout, like the notorious New York City blackout of 1965, and the severe blackout of 2003 effecting the northeast and mid-west United States and central Canada, that shock us into realizing the electricity is not only a product and service, but also a complex industry that includes a surprising variety of players with a diversified range of interests.

For nearly a century, except the very beginning, the electric industry in all countries or jurisdictions has been thought of as a "natural" monopoly and regulated[1], where efficient production of electricity required reliance on public or private monopoly suppliers subject to government regulations of price, entry, investment, service quality and other aspects of business behavior.

Beginning in the 1980's, dramatic changes have been taking place in the structure of the electric industry in many jurisdictions around the world. Deregulation has broken the vertically integrated players, often previously

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[1] It is doubtful that the electricity industry, for technical or efficiency reason, ever had to consist of vertically and horizontally integrated monopoly firms. Some argue that the monopoly was not natural, and a political monopoly was sought instead. For more discussion see, for example, Tomain (2003), Grossman (2003), and Bradley (2003).

government-owned or government-operated, into pieces and introduced competition in both generation and retail sectors. Consumers were often led to expect lower power price and better service in terms of multiple service packages. The changes are designed to foster competition in the generation segment through an end to the need for regulatory approval of new generation, and to establish new incentive based regulation of the transmission and distribution (T&D) functions, which are likely to remain and continue to be viewed, at least in nearly foreseeable future, as natural monopolies (Joskow, 1997).

The movement to restructure the electric industry was influenced by the combination of politics, economics, and technology. The fundamental drive is the desire to reduce the power cost (including the high cost of regulation), to allow consumers to access cheaper electricity, to eliminate or to reduce heavy-handed price setting regulations, to increase economic efficiency, and the most importantly, to promote competitive markets that are widely believed to benefit all consumers (Tomain, 2003). Deregulation critically shifts decision making from the government, or government-influenced agencies, to markets themselves, and for the first time, give consumers a choice to select their power providers.

The experience and outcome in each jurisdiction is diverse. Some markets, for example, Britain and Scandinavia, have likely reaped most of the benefits of deregulation, whereas other markets, for example, Alberta and California, have experienced more difficulty. Inspired by relatively successful initial experiences, many nations or jurisdictions considered deregulation. However opponents of deregulation are not silent. The recent California deregulation crisis with many brownouts and skyrocketing power prices has shaken the support for deregulation, even provoking another round of debate between deregulation and re-regulation. Studies of deregulation in many countries has supported the strong expectation of a better economic performance of a deregulated power industry; it also shows that deregulation can result in lower costs and broader array of choices to consumers (OECD/IEA 1999, Armstrong *et al.*, 1994). Some hold the view that deregulation will benefit both the power industry and its consumers in the long-term but with a likely-to-be-tough transition period. Others have lost faith in deregulation; Ontario, for example, has recently backed away from full deregulation of its power market.

A brief introduction of the electric industry and a detailed literature review on deregulation and price risk management, including power price, DSM, and market power, are discussed below.

A.1 Historical Perspective

A.1.1 Birth of Electricity Industry

Electricity[1] was the source of experiments and curiosity among a few scientists and many rich dilettantes as far back as the early 1600's. It was an interesting curiosity until the 19th century when practical inventions and breakthroughs, including the invention of power generator, light bulb, and adoption of alternating current technologies in the Victorian Era brought an opportunity for the electricity to walk into practical use from laboratory.

If Thomas Edison's Pearl Street Station, which began its service to 85 customers in New York on September 4, 1882, was the beginning, the electricity industry took a long journey before it reached today's extensive grand enterprise. Initially, technological entrepreneurs like Edison and Westinghouse capitalized on their inventions and patents by creating companies to sell electric power, appliances, and everything required for its use, including small items such as light bulbs and light fixtures. The earliest electric power utilities were characterized by the selling of lighting, not electricity. The initial markets were deregulated and severely competitive.

A.1.2 Emergency of Regulation

The focus of utility companies changed, a pattern that has continued until today. Demand for electricity grew, and an urgent need for large-scale generation in non-urban settings, with transmission of power to urban centers, emerged. Later in the 20th century a move for rural electrification, involving even larger transmission and distribution grids, grew as well. These activities increased the risk of investment in the electricity industry; in addition, electricity was often provided by a single provider to many customers, who were then vulnerable to monopoly pricing. The response was either direct government investment in the industry or regulation of private firms. In the early 1900's, vertically integrated electric utilities, controlling generation, T&D operations, and power selling and service began to function in "exclusive franchise areas" with insured profit earned from fixed return rates. The industry had cost intensive capital investment, long equipment lifetimes, low variable operating cost, and a need for ongoing maintenance.

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[1] William Gilbert, a physician in Queen Elizabeth of England, first coined the phase "electrica" in 1600 from the Greek work for amber, elektron. Amber was the only known material at that time produced static electricity.

The public, government, and business favored regulation during the early history of the industry, since it offered a relatively risk-free way to finance the creation of power industry for both business and individual consumers. Without regulation a universal power system reaching all homes and businesses, which we take for granted today, would never have been built.

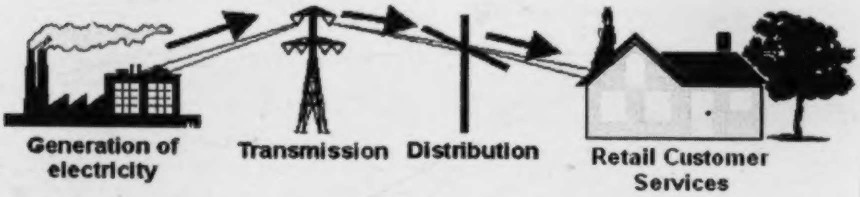
A.1.3 Return of Competition

As the power industry developed, the perceived needs for regulation changed. Electricity is no longer novel, and its use has spread far beyond its initial market, lighting. Investing in the electric industry is no longer seen as high risk. The growth in demand for electric power began to slow down. In addition, other regulated industries had gone through deregulation with positive outcomes: for example, natural gas, telecommunications, and airline transportations. This inspired a review of whether regulation of electrical power still filled a socially useful role

Consequently, a call for bringing back competition in the electricity industry was embraced by many jurisdictions. For example, Britain, the U.S., and many other nations or jurisdictions opened, or have been contemplating opening, their doors to competition, initially in the electricity supply markets, with the objectives of providing better services, and encouraging innovations. It was believed that if competition for power generation emerged, then over a short-term, average power prices would drop in most regions due to competition, and in a long-term, average power prices would be reduced as result of efficiency improvements or other cost reductions. A preliminary analysis of the U.S. power industry through 2015 supported this vision (Energy Information Administration, 1997).

A.2 Electric Power Industry as a Regulated Monopoly

As power infrastructure grew in scale and cost, the power industry began to be characterized as a vertically integrated and regulated monopoly, a business and market structure that persisted over 50 years. Electric utility is a traditional term for either an investor-owed utility (IOU), i.e., a private company, or a government-operated department or company; they generate, deliver (i.e., transmit and distribute), and sell electric power, as shown in Figure A-1 (Philipson and Willis, 1999; Glover and Sarma, 2002).



(Source: After The Changing Structure of the Electric Power Industry 2000: An Update, U.S. Department of Energy, 2000, available online at http://www.eia.doe.gov/cneaf/electricity/chg_stru_update/toc.html.)

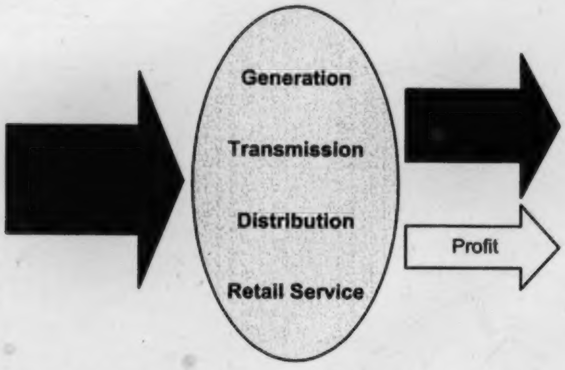
Figure A-1 Functions of An Electric Utility.

Usually a vertically integrated electricity utility performs all four functions. Table A-1 lists the functions each part performs. In the traditional electric industry, many electric utilities perform all four functions relating to power generating, delivering, and selling, while others perform only one or two. They have some of the following characteristics:

- **Vertically integrated structure**: all the four functions were intertwined into one company or department. Revenue from the delivery and sale of power will be used for cost recovery involved in all sections of generation, transmission, distribution, and retail services. The difference between revenues and cost recovery is the profit, which can be retained in the utility company or shared by investors, as shown in Figure A-2.

Table A-1 Fundamental Functions of the Four Parts in an Electric Utility

Function/Part	Description
Generation	Generating electric power by converting some other forms of energy, for example, hydro, coal, nuclear, or sunlight, into electricity.
Transmission	Moving bulk quantities of high voltage electricity from long distance generation stations to local distribution stations.
Distribution	Delivering power to consumers, which involves breaking up bulk quantities of high voltage power into low voltage "household" size amount, and routing it to business and homes.
Retail Customer Services	Selling power and providing customer services, including measuring and billing consumers for the power consumed, and perhaps providing other services, such as an energy efficiency.



(Source: After Understanding Electric Utilities and De-regulation, 1999, Philipson and Willis, Marcel Dekker, New York, NY.)

Figure A-2 An Traditional Vertical Integrated Electric Utility.

- **Monopoly franchise**: a monopoly franchise is granted by the local government, which grants a utility company exclusive rights to produce, deliver, and sell power in their service territories. In addition, franchise holders had an obligation to serve if requested, had a guaranteed rate of return subject to a test of prudence, and had to accept regulatory oversight of their operation, pricing, and other business conducts.
- **Cost-base price**: the government will define the utility cost and set power cost-based prices which will ensure the utility a certain return of its

investment and operation. Usually, it requires that the utility operate in a "lowest cost" manner.

Such an electric utility will not exist after deregulation since two of the traditional parts will be replaced by competitive companies (generation and retail), and two (transmission and distribution (T&D)) will continue to be regulated, although most often as separate entities.

A.3 Power Deregulation

A.3.1 Impetus of Deregulation

The main motivation for deregulation[1] of the electric industry is the desire for a low power price, more innovation, less regulatory cost, and better services in terms of multiple service packages for consumers. Reasons for deregulation vary somewhat between jurisdictions, but can be categorized in the following groups.

1. Needs of regulation vanished or changed.

The original need for regulation, which was to provide relative risk-free financing of the electric system development (from both perspectives of government and business), became unimportant decades ago. While electric utilities continue to finance by borrowing money, which is mainly used to re-new their system, this does not represent the same level of risk in investment as it did in the late Victorian era. Today's additions are only incremental in nature. In addition there is no risk from technology as there was when electricity was a new invention, and hence no doubt about the existence of a market for electric power.

2. Political goals changed.

In many of the nations, electricity deregulation followed government-initiated privatization of the industry. For example, the electricity deregulation in Britain is a direct result of the Thatcher government's desire for efficiency and the privatization of the electric industry (Czamanski, 1999; Beder, 2003). Deregulation is coincidental with privatization in most national areas, and is seen as necessary in order to foster competition and attract investment.

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[1] "Restructuring" is used advisedly, see reference, for example, by Tomian (2003).

3. Power cost is expected to drop more.

Regulation and the lack of competition is perceived to provide a disincentive to improve on existing performance or to take risks on new technologies that might reduce the cost of power production, whereas competition is perceived to breed innovation, efficiency, and lower cost. The electric industry had not seen competition for near a century. Power prices had declined somewhat as the technologies developed, but not as much as where there had been with competition (Philipson and Willis, 1999).

4. There was a desire to improve customer value.

Competition was seen as an environment that would place more focus on increasing the consumer's value, for example, by offering additional or premium services or options, even at a higher cost or providing time of use packages that matched a customers usage patterns.

5. Environmental requests increased.

Economists and policy analysts have long argued that the most significant potential gains from electricity deregulation will stem from changing the way investment and consumption decisions are made (Borenstrin and Bushnell, 1999). A variety of alternative energy sources with reduced emissions (for example, wind power to reduce greenhouse gas emissions) are available, and it was perceived that in a deregulated environment these kinds of technologies could be developed quickly on a smaller scale, without the burden of extended regulatory hearings.

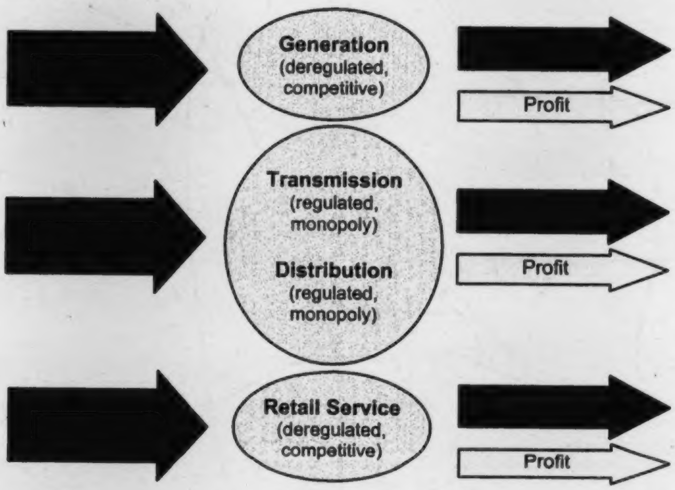
Moreover, the successful experiences and improved performances in other industries, such as natural gas, telecommunication, and airline transportation, helped create a momentum for deregulating electrical power.

A.3.2 Changes after Deregulation

The traditional electric utility is a vertically integrated entry with generation, transmission, distribution, and retail service. The key concept of deregulation is that no one company should have a monopoly on either the wholesale segment, generation, or the retail sale of power and power-related services. Jurisdictions that have deregulated the electric power industry have been moving toward a framework in which customers will have a choice among competitive power providers, and the following dramatic changes have been taking place:

1. Electricity generation and service is unbundled from delivery, i.e., T&D

A traditional electric company is unbundled into three parts: generation, T&D, and retail service, as shown in Figure A-3. Note that in some cases transmission and distribution are unbundled, creating four entities. The power generation and retail sale service are deregulated, then competitive, while the T&D remains regulated and monopoly franchised. The revenue from the operation of each part is merely used for its own cost recovery. The profit, the difference between the revenue and the cost recovery, will be retained, in part, within the company or distributed to its stockholders.


Generation
(deregulated, competitive)
Profit
Transmission
(regulated, monopoly)
Distribution
(regulated, monopoly)
Profit
Retail Service
(deregulated, competitive)
Profit

(Source: After Understanding Electric Utilities and De-regulation, 1999, Philipson and Willis, Marcel Dekker, New York, NY.)

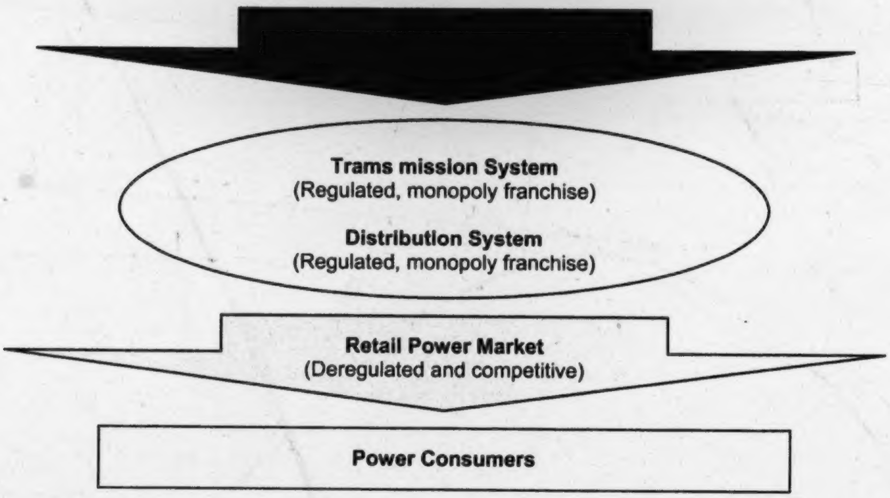
Figure A-3 An Deregulated Electric Utility.

2. Open access to T&D grid.

To protect and ensure power-producers and power-buyers have fair opportunities to compete, open access to the T&D systems is provided in the public interest by a monopoly franchise holder, who does not sell or buy power, but merely has the duty to operate the grid. The main argument in favour of a single monopoly T&D firm concerns the set up cost of a T&D system. However, there is increasing doubt about the premises of the monopoly argument for the T&D section, and even some extent intra-network competition has been suggested (Künneke, 1999).

3. Competitive power markets established.

Under deregulation electric power from a competitive wholesale market flows through a T&D grids to a competitive retail market, then finally to end-users, as shown in Figure A-4. Often the retailers in retail markets are buyers in wholesale markets. Under deregulation, a power market, a completely new concept, where power producers can offer and consumers can buy and transact the sales, is necessarily established. There are three elementary ways a market can operate,


Trams mission System
(Regulated, monopoly franchise)
Distribution System
(Regulated, monopoly franchise)
Retail Power Market
(Deregulated and competitive)
Power Consumers

(Source: After Understanding Electric Utilities and De-regulation, 1999, Philipson and Willis, Marcel Dekker, New York, NY.)

Figure A-4 Completely Deregulated Electric Power Industry.

pool-based, exchange-based, and bilateral-based trading. In reality, often these three formats are combined in different ways in a composite system.

- Pool-based Market

  The pool-based market is a "one buyer" mandatory system, which is often a governmental or quasi-governmental agency that is responsible to buy wholesale power for everyone, taking bids from all sellers, buying enough power for the total demand, taking the lowest-cost bidders, and dispatching the power at a uniform clearing power price. Usually, the pool-based market operator also has the responsibility of running the power system, and thus is a combined buyer-system operator.

- Exchange-based Market

  The power-exchange market, a so-called voluntary pool market, is a trading exchange for electric power, which in general, is set up by jurisdictional governments. The exchange market operates much like a stock or commodity exchange. Buyers enter their need into the power exchange and so do sellers. Similar to a stock market, a power exchange market constantly updates and posts a market-clearing price, which is the current price at which transactions are being made. The power exchange thus is a power commodity market with fluctuating prices, depending on demand, just like the markets for any other commodities.

- Bilateral-Exchange Market

  The bilateral-exchange market is a multi seller and multi buyer system, where individual trader can make a deal to exchange power at privately agreed prices and conditions. However, the traders may be required to disclose some or all of the details of their transactions. The bilateral contracts can be regarded somewhat as medium term hedging contracts between power traders. The power market in Texas belongs to this group. This model serves in many jurisdictions apart from or in conjunction with a pool or exchange market, for instance, in California, New England, PJM, and Alberta, which allow the operation of bilateral markets.

The details of implementation of these three types can vary a great deal between jurisdictions, such as the extent of privacy of bilateral contracts, and the time period of power sale, such as hour-ahead or day-ahead trading. However some primary main features, shown in Table A-2, are common.

Table A-2 Features of Pool-based, Exchange-based, and Bilateral Markets

Type	Number of Buyers	Number of Sellers	Buyer knows Seller?	Uniform Price?
Pool-Based	One	Multiple	Yes	Yes (Usually)
Exchange-based	Multiple	Multiple	No	Yes
Bilateral	Multiple	Multiple	Yes	No

A.3.3 Debate of Deregulation vs. Re-regulation

Deregulation began with enthusiasm and an expectation of lower prices and better or more service; initial experience in Britain was positive and reinforced this expectation. However, the experience of deregulation in other jurisdictions did not fully live up to those expectations. In particular, the 2000-2001 California electricity crisis and the collapse of Enron evoked another round of debate about whether the electric industry should continue the deregulation or return to the cost-based monopoly regulation (Roach, 2003).

The deregulation process does need appropriate market regulations in the transition stage to help the market learn how to work well and benefit its participants (Ramos-Real, 2004). Borenstein and Bushnell (2000) pointed out that the movement toward less regulation has not only enormous potential benefit but also potential risk. Consumers in deregulated power markets may in fact find it more costly in the short run than with their regulated predecessors. The long-term gains from improved investment decisions on both demand and supply sides must be sufficient to outweigh the potential short-run costs. Studies comparing 19 Organization for Economic Cooperation and Development (OECD) countries[1] even argued that the unbundling of generation and retailing from T&D, and the introduction of wholesale spot markets did not necessarily lower power prices and may possibly have resulted in higher power prices (Steiner, 2001; Hattor and Tsutsui, 2004).

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[1] The 19 OECD countries are: Australia, Belgium, Canada, Denmark, Finland, France, Germany, Greece, Ireland, Italy, Japan, the Netherlands, New Zealand, Norway, Portugal, Spain, Sweden, the United Kingdom, and the United States.

A.3.4 Deregulation in Practice

For over one hundred years, the electric industry in nearly every country worldwide operated as a regulated industry. Movement toward a deregulated electric power system did not occur until the last part of the twentieth century, and then it was undertaken in a piecemeal fashion. Beginning in the 1980s, many countries, for example, Britain (Surrey, 1996; Green, 1998; Newbery; 1999), the U.S. (Joskow, 1997; Flowers, 1998), and Australia (Moran, 2002; Beder, 2003, Phunnarungsi and Dixon, 2003) began to experiment with the deregulation or the reconstruction of their own power industry. Many other countries or jurisdictions have been inspired to begin their own regulatory reforms to achieve more efficiency in their power industry.

The exact way in which deregulation and competition manifest to the power industry varies depending on local laws and regulations. Deregulated power markets are significantly different based on natural resources and generation technology (the generation mix, for example, how much power generation capacity comes from hydro, coal, natural gas or nuclear power). Thus there is some question whether a right model exists that will fit all or a majority of markets, even though some attempts to gain insight into how various aspects of the competitive markets might evolve have been made (Larsen and Bunn, 1999; Kiesling and Mannix, 2003). This means that there will be a need for each country or jurisdiction to adapt, e.g. combine existing models, or invent a model that is suitable for itself, and for each electricity company in each market to understand, learn, and develop and tailor efficient strategies to that country.

Nevertheless, changes after deregulation are similar in many jurisdictions: power consumers, including major business, small commercial and residential power consumers, will be able to choose their power retailers or providers, just as they shop for long distance or local telephone. These retailers or providers can deliver power through an open access T&D grid to their consumer. A bibliographical survey introducing the general background and development in the field of power system "wheeling", i.e., delivery, under deregulated environment are given by Sood *et al.*, (2002). Several typical deregulation cases have been presented to describe deregulation in different jurisdictions.

A.3.4.1 Deregulation in North America

Deregulation in the U.S. was primarily driven by business interests, in particular, industries that used large amounts of electricity and wanted to be able to reduce costs by making deals with competitive suppliers and private power companies that wanted an opportunity to take profits from the electricity business previously monopolized by the regulated utilities. In addition, a series of successful deregulation experiences in the 1980's in the airline industry, then natural gas, petroleum, financial services, telecommunications, and railroad freight transportation, plus British and Australian relatively successful experiences with power deregulation, inspired the U.S. to reconstruct its electricity industry starting in 1978 with the hope that competition would increase customer choices, lower prices, and encourage innovation (Flowers, 1998; Czamanski, 1999; Energy Information Administration, 2000; Beder, 2003).

Progress was slow until 1996; the year deregulation began in some U.S. markets. Significant steps have been undertaken to promote wholesale competition, and to explore the flexibility of extending to the retail level. The changes that followed have transformed one of the largest industries in the U.S., valued at over $200 billion, into one with minimal public safeguards, highly fluctuating prices, multiple opportunities of profits and losses, and various degrees of competition. Deregulation began in New York, PJM (which includes Pennsylvania, New Jersey, Delaware and Maryland), the Ohio area, and California. Texas deregulated in 2003. All of the U.S. has taken at least some steps towards deregulation at the wholesale level, but full deregulation at the retail level, including customer choice, is more limited (Sundhararajan *et al.*, 2003; Zarnikau, 2004). Canada began power deregulation when Alberta made its first announcement of deregulation in 1996 in order to introduce competition and attract investment. After four year of preparation that included requiring existing utilities to create separate companies for generation, T&D and retail, Alberta first opened its deregulated wholesale pool-based market, the Alberta

Power Pool (PPOA), in 2000. It became fully deregulated in 2001 when all small and residential consumers were introduced into the market. Ontario began its deregulation in 1998, lobbied by businessmen and labor Unions, and put its deregulated market into limited operation in 2000. The deregulated market shortly thereafter was on hold due to the unexpected skyrocketing power prices.

California Crisis

California, one of the first states in the U.S. to deregulate power, first approached deregulating 1994. In 1996 the state passed the law (AB 1890) enabling generation to be competitive, allowing consumers to choose their power suppliers, and opening a fair access to a regulated restricted T&D grid to all power generators. Power was traded at a newly created market, CalPX[1]. On March 31, 1998 competitive retail power for all residential consumers was introduced. In addition to the establishment of a competitive power market, the deregulation bill authorized the recovery of stranded costs of utilities[2], and the deregulating legislation established funding for a public interest program, including conservation research and development, and renewable energy resource development.

However, contrary to expectations deregulated wholesale power prices in California were higher than before. In late 2000, the prices skyrocketed, businesses and residents experienced many brownouts, and the state faced a continuous threat of power outages. As consequence, the two largest IOU's, the Pacific Gas & Electric Company and the Southern California Edison Company, faced bankruptcy and the government had to intervene and declare a temporary state of emergency. Neither customers nor generators except some out-of-state generators[1] are happy with the current deregulation, which also provoked great political turmoil (Shioshansi, 2001).

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[1] The California PX cased functioning in January 2001.

[2] Assembly Bill 1890 provided an opportunity for the utilities to recover their "stranded cost" by collecting a mandatory charge from virtually all consumers and by securing of parts of their stranded cost.

The reasons the California deregulation turned into a nightmare are complex. A seriously flawed market design implemented since 1998 is considered to be fundamental: the wholesale market was competitive and the retail market was regulated with fixed price, which veiled true price signals to power consumers and, in turn, discouraged energy conservation (Woo, 2001; Jurewitz, 2002; Ritschel and Smestad, 2003). Other factors include market power (for instance, strategic withholding of power), sustained demand growth unmatched by new generation capacity (aggravated by California's ponderous processes for environmental review of new power projects), rising marginal cost, and financial insolvency (Puller, 2002; Woo, 2001; Borenstein *et al.*, 2002; Wolak, 2003b). The fact that demand exhibits virtually no price responsiveness, and supply faces strict production constraints combined with very costly storage drove volatility in prices. The resulting price spikes would be smoothed out significantly by encouraging price-responsive demand and long-term wholesale contracts for electricity (Borenstein, 2002). Some view the California electricity crisis was fundamentally a regulatory crisis rather than an economic crisis[2] (Peterson and Augustine, 2003; Wolak, 2003a).

PJM Steadiness

PJM Interconnection[3] was the first major power pool in the U.S., operating the world's largest competitive wholesale power market., It is a regional transmission organization (RTO) that coordinates the movement of wholesale electricity in order to balance load, realize operating economics, save capital investment, and enhance system reliability; it has operated since 1997. PJM West was connected to the system in April 2002. PJM has developed issues deserving attention, including high level and volatility in prices, thin market, poor liquidity, and high emissions of hydrocarbons (Lock and Stein, 1996; Tomain, 2003).

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[1] Such as Duke Power, Dynegy, and Enron that owned many of the power plants formerly own by California utilities, are now reaping handsome profits.

[2] It was argued that the U.S. Federal Energy Regulatory Commission (FERC) and state policymakers were unable to work together to resolve the crises. The conflict and regulatory dispute between the FERC and the state over the appropriate regulatory response to the extremely high wholesale power prices exaggerated the crisis. This crisis is finally solved not by the FERC interventions but by vigorous state actions restoring the balance of supply and demand.

[3] The geographical area covers, in all or parts of, Delaware, Maryland, New Jersey, Ohio, Pennsylvania, Virginia, West Virginia and the District of Columbia.

PJM market operates on a balancing and day-ahead basis, and provides power buyers and sellers the opportunity to trade through spot transactions or bilateral agreements. The day-ahead market is a voluntary bid-based market, where the locational market clearing prices are calculated on an hourly base, and has been implemented since June 2000. Most significantly, PJM is now recognized by the FERC as a RTO of choice for the entire northeast, and therefore become a RTO template of choice, with profound influence over the market design, technology, and politics of power deregulating or reconstructing in the U.S. (Masson, 1999; Lambert, 2001; Mansur, 2001; Ott, 2002).

Alberta: Functioning but Volatile

In the mid-1990s, in order to introduce competition and attract investment, the Alberta government decided its electric power industry needed an overhaul (Waveman and Yatchew, 1996; Alberta Resource Development, 1999; Lawrence and Sanderson, 2001; Wellenius and Adamson, 2003). The first movement toward deregulation, introduced by the Electric Utilities Act of 1996, allocated the control of generating power from the previous three monopoly companies, i.e., EPCOR, TransAlta and ATCO, to a wider array of market players[1]. The T&D grid remains regulated, but provides an open access to generators and consumers[2]. A pool-based market, through which all power is traded, was established in 1996. The full wholesale and retail markets began on January 2000 and January 2001, respectively. Power prices are set by the marginal generation capacity and on an hourly basis. Bilateral contracts are in effect allowed and traded through the PPOA by bidding at zero prices, which ensure the power will be dispatched. The Alberta's government was forced to institute a price cap, which has remained as a protection for consumers from higher prices, since December 2000.

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[1] This was done by two auctions, the Power Purchase Agreement in August 2000, and the Market Achievement Plan in December 2000. The only generating plants remaining as regulated pricing are TransAlta's hydroelectric plants, which contribute approximately 10% of Alberta's total generating capacity and dedicated to the Transmission Administrator to provide system support services and emergency reserves.

[2] In 1999, a limited retail access program was available to both industrial and commercial customers with time of use meters.

In Alberta, load capacity is dominated by coal-fired generation, while gas-fired capacity dominates at the margin. Over the last five years, Alberta electricity demand has approximately tracked Alberta GDP's growth. The initial low reserve margin and the load growth prompted a large number of new generation projects; many were combined-cycle plants, based on then low natural gas prices and lower emissions. Today Alberta has a healthy reserve margin that will increase when the Genesee coal fired project comes on line in the winter of 2004/5. The Alberta power market is linked to the entire Pacific Northwest and California via the British Columbia system. As a result, the Alberta power market is affected by what happens in the rest of the region. Chapter 4 discussed Alberta high power prices that occurred just after deregulation due to limited power capacity and increased power demand, which consequently drew so much political and public attention that temporary retail price caps were established. Some have discussed returning to re-regulation right following the high prices in the California crisis (Woo *et al.*, 2003).

Many articles discuss other markets, for example, the New England Pool (NEPool) see Bushnell and Saravia (2002); New York Power Exchange see Lawrence and Neenan (2003); the market in Texas see Sundhararajan *et al.* (2003), and Zarnikau (2004); the market in Ontario, see Chan (2002).

A.3.4.2 Deregulation in Europe

Britain is the market most cited as a successful example of a deregulated power market. Britain began its electricity deregulation in 1996 motivated by seeking efficiency and impelled by Thatcher's government, and has opened up a majority of the market (Ruff, 1989; Lester, 1991; Littlechild, 1992; Armstrong *et al.*, 1994; Green, 1998; Masson, 1999). Unlike voluntary arrangements in some U.S. markets, the British pool-based market, established in 1990, is mandatory for all licensed generators and suppliers (e.g. the wholesale level). In general, pool members are obliged to sell and purchase power from the markets under its trading agreement. The power price changes every half hour based on system marginal pricing (SMP). A certain degree of hedging against price fluctuations is possible through bilateral contracts. These so-called contracts for difference (CFD) are mechanisms for allocating part of existing financial risk without trading in power (Czamanski, 1999; Newbery, 1999; Bushnell and Saravia, 2002; Wolak and Patrick, 1997).

The Nord Pool in the Scandinavian area, which is the first multinational market, began its trading back in 1996, when Sweden's power market merged with the previous Norwegian market operated since 1992. In 1997 Finland joined and all customers in Nord Pool can change their suppliers at will and free of charge. With the ratification of the Energy Law Amendment at the end of April 1998, Germany opened its market, the LPX, completely for all end users and supply companies in June 2000 (Masson, 1999; Houmöller, 2000; Midttum, 2000; Johnsen, 2001 and 2003; Flatabø *et al.*, 2003). Other countries, such as Spain (González and Basagoiti, 1999), and the Netherlands also deregulated their power industry and opened their own deregulated power markets (http://www.apx.nl/home.html).

A.3.4.3 Deregulation in Australia and New Zealand

Since the beginning of the 1990s, the electricity sector in Australia has undergone a period of radical overhaul. The Australian National Electricity Market (NEM), another successful example of mandatory pool-based deregulated power market, commenced operation on December 13, 1998. The spot-clearing price matching supply and demand is calculated for each half-hour period during a trading day. Financial contracts, e.g. bilateral hedging, are allowed to a certain extent to manage the risk created by price volatility in the market (Brennan and Melanie, 1998; Wolak, 2000; Moran, 2002; Beder, 2003; Phunnarungsi and Dixon, 2003).

The NEM spans the power system of New South Wales, Victoria, South Australia, Queensland, the Australian Capital Territory, and the Snowy Mountain

Area. The NEM was implemented in stages. Victoria and New South Wales established their own power market in October of 1994 and May of 1996, respectively. In May 1997, the New South Wales system provisionally joined Victoria's power market VicPool that then formed the early NEM. In 2001, Queensland was connected to the NEM. The NEM formally commenced in December 1998.

The NEM system is modelled after the British market, but being younger, includes many differences that aim to avoid some of the problems that have become apparent in the British market; the modifications including simple bidding structure, no capacity payment, and zonal transmission pricing (on half hourly base) (Masson, 1999; Beder, 2003). The NEM is technically a success but, as in Britain, questions remain about the extent to which pool prices are driven by true competition. Until 2002, the NEM prices were capped at a maximum of AUD5000/MWh while a normal power price is AUD35/MWh, and then increased to AUD10,000/MWh. Such high price caps offered little protection to buyers.

During the 1990's the electricity industry in New Zealand experienced massive change through extensive reform initiated by the government. Today, New Zealand enjoys a new competitive electricity market with separated T&D, generation operations, and several large private-sector players. The voluntary pool-based wholesale power market is supplemented by trading a range of forward contracts; New Zealand Electricity Market (NZEM) established in 1996, is the actual trading arrangement where most wholesale electricity is bought and sold on a daily basis. NZEM deals with multilateral contracts and retail competition is allowed (Alvey *et al.*, 1998)

A.3.4.4 Deregulation in Latin America and Asia

Aware of the different experience in Northern America, Europe, and Oceania, most developing countries in Asia and Latin American are either contemplating or implementing their own deregulation.

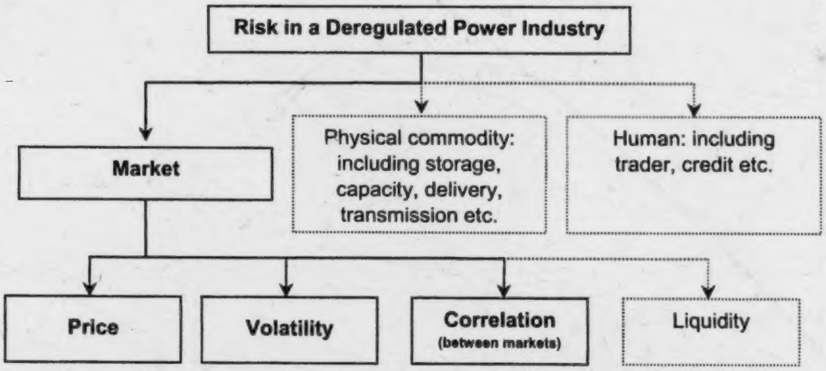
Countries in Latin America, including Chile, Argentina, Uruguay, and Brazil, having been at the forefront of innovation in the creation of electricity markets, began their large-scale privatization of their electric industry (which is always regarded as a prelude of deregulation) back in the 1990's. Goals are similar, being lower power costs and prices, enhanced competition, and more access to private investment. However serious problems, including limited competition, market power, even service stoppage, e.g. blackouts in Chile, have reinforced lingering concern about the advantages of deregulation (Spiller, 1996; Rudnick and Zolezzi, 2001).

Electricity reform in Asia is in early stages of discussion and/or implementation. Japan, Hong Kong, Singapore, Thailand, and China, have been discussing moving to deregulated power markets, and a few have conducted limited deregulation experiments (International Energy Agency, 1997; Lam, 2004). However, a model approach to the T&D has been suggested for developing Asian countries (Leeprechanon *et al.*, 2002). A clear trend of convergence toward to the standardized market design with the main objectives of market liquidity and pricing efficiency was suggested, including locational marginal pricing (LMP)-based power market, financial transmission right (FTR) market for short and long-term congestion hedging, and ancillary service market (Scott, 2002; Ma *et al.*, 2003; Liu *et al.*, 2003).

A.4 Deregulated Power Prices

There are many challenging issues under the newly deregulated competitive power markets. Instead of centralized decision-making in a vertically integrated environment as in the past, decision-making is now decentralized and driven by market forces. Gaming, e.g. an exercise of market power by strategic holding of power, and price excursions have been observed in almost every deregulated power market (Guan *et al.*, 2001; Guan 2002; Bialek, 2002) but explicit analysis of these phenomena is limited.

Risk assessment and management in deregulated power markets is extensive, and can have some international issues in various implementations (Fusaro, 1998; Pereira, *et al.*, 2000; Denton, *et al.*, 2003; Dahlgren *et al.*, 2003). One can think of three types of risk occurring in deregulated power markets: market, commodity, and human, as shown in Figure A-5. Risk from commodity and human is beyond the scope of this research. In this research the author looks at price patterns and volatility to illustrate differences in market risk between markets.


Risk in a Deregulated Power Industry
Market
Physical commodity: including storage, capacity, delivery, transmission etc.
Human: including trader, credit etc.
Price
Volatility
Correlation (between markets)
Liquidity

(Source: After Energy Risk Management, Fusaro, P., 1998, McGraw-Hill, New York, NY.)

Figure A-5 Risk in a Deregulated Power Market.

Successful market risk management requires an understanding of the nature of price, volatility and the correlations between markets, as well as the problems inherent in calculating estimates of these quantities. Extensive summary and discussion have been addressed by, for example, Fusaro (1998) and Allen and Ilic (1999). Pilipović (1998) discussed the valuation and management of energy derivatives focusing on the quantitative analysis from the managerial and implementation perspective. A state-of-art summary of risk assessment in energy trading and some essential references was given by Dahlgren *et al.* (2003). Real option models and stochastic optimization techniques were proposed to measure and manage the market risk (Denton *et al.*, 2003).

Price uncertainty fuels power derivatives and risk management. The literature in this area is reviewed from five aspects: power pricing, price behavior and volatility, price modeling or forecasting, DSM, and market power. Relevant literature about policy issues, including price cap, will be reviewed accordingly.

A.4.1 Power Pricing

Deregulated power markets are, in general, designed to achieve two objectives: 1) market liquidity, which facilitates bilateral trading, and 2) pricing efficiency, which facilitates transmission congestion management. The effort to balance these two objectives has led to marginal clearing pricing (MCP) in most deregulated power markets, which is set based upon the marginal generation bid of the last generator required to serve the load. MCP includes three types: uniform, zonal and locational.

Unlike locational (or nodal) marginal pricing (LMP), uniform marginal pricing (UMP) and zonal marginal pricing (ZMP) rely on pre-defined regions within which transmission congestion is insignificant, and hence, price can be deemed uniform. A UMP approach would work if there should exist ample transmission capacity where congestion is of no concern within the UMP regions. When this is not true, UMP gives wrong price signals and causes difficulties in the physical system operation because power is bid into congested areas. This reduces market efficiency.

The development of ZMP, an improvement over the UMP model, is based on an assumption that transmission constraints are few, and an identified "*a priori*" can be used to delineate the network into several zones. A uniform power price is then computed for each zone. However, practical experience has proven that the number of transmission constraints is not few, the congestion pattern is unpredictable, and the zonal price signals based on predefined zones do not always relieve congestion.

Unsatisfactory experiences with UMP and ZMP led to the development of LMP, which is based on a full transmission network and determined via a security-constrained economic dispatch. LMP-based methods were implemented notably in many markets, for example, PJM (Ott, 2003), New York ISO (Lawrence, 2002; Neenan Associates, Inc., 2002; Lawrence and Neenan, 2003), and Australia NZEM (Alvey *et al.*, 1998). A LMP signal at a specific location reflects the marginal cost of serving the last megawatt of load considering the marginal production cost; the impact of locational factors, and in some cases the marginal effect of transmission losses. LMP has proven its effectiveness in achieving congestion relief and market efficiency.

Without appropriate financial hedging instruments, the unpredictability of transmission congestion implies greater uncertainty of LMPs, creating price volatility. Point-to-point FTRs were developed, for example, in PJM, to address price volatility and to increase market liquidity. FTRs overcome the congestion-incurred price uncertainty and markets liquidity problems that are otherwise impediments to the LMP method.

A.4.2 Price Behaviors and Volatility

Electric power is one of the few commodities in the world that offers the opportunity to study independent prices of the same commodity in various markets. Electric power is not practically storable; it is not transported over oceans except for short distances to islands, and has a significant cost for long distance transport over land. As a result, the price of power in one deregulated market can change independent of the price of power in another distant deregulated market.

This stands in contrast to oil, which is easily and cheaply transportable by ship and pipeline. Oil prices in different areas of the world vary only by quality and transportation differentials; there is essentially one world price for oil. Natural gas is more expensive to transport by pipeline or as liquefied natural gas (LNG), and capital facilities take a long time to construct, but over time, these transportation options again drive a world price adjusted for transportation differentials.

The fact that electricity is not storable also leads to high hourly variations in price in deregulated markets. Unlike other commodities, it is not unusual for electric power to show both a significant daily variation in price and large variations in average price between days.

For these reasons, the power price in deregulated markets provides a unique opportunity to study inter-market variations in the price of a basic commodity. Reviewing the different approaches measuring power price correlation and examining the relationship between power and other commodities suggests that the relationship between spot and future prices in deregulated power markets is unique (Alexander, 1999). Price volatility in deregulated markets is both high and variable over time. In the competitive environment, power players (including investors, buyers and traders) not only need insight into prices, but also need insight into the assessment of the risks of buying and selling power at the forecast prices. An implication of the understanding of price is discussed by Bhanot (2000).

A.4.2.1 Prices in Individual Markets

Examination and analysis of deregulated power price behaviors in individual market are documented by many researchers.

High prices and notable price volatility caused by the exercising of market (von der Fehr and Harbord; 1993; Littlechild, 1998), and price caps (Robinson and Baniak, 2002) are persistent problems in Britain. In particular, Wolak and Patrick (1997) looked in detail of the time series properties of power prices, and found that power price has tremendous variability, even over very short time horizon, and is a less accurate forecast compared to load. Mount (1999) found that uncertainty in the load due to forecasting errors will be amplified into a high price volatility, price spikes are more likely to occur when the expected load is high and the level of market power is at its greatest. Price spikes also occur after unexpected outages of generators or transmission lines. A discriminatory price auction is proposed as a better alternative that would reduce the price, responsive to errors in forecasting total load.

By looking at daily, weekly, and seasonal patterns, Knittel and Roberts (2001) found that power price in California shows a high degree of persistence in price level, and strong deterministic cycles. Other researchers have contributed to examining power price behavior, especially the price spikes during the California market crisis in 2000, and identified reasons for market power (Puller, 2002; Guan *et al.*, 2001; Borenstein *et al.*, 2002; Wolak, 2003b), market rules and structure (Wolak and Patrick, 1997; Mount *et al.*, 2000), and elasticity of price-responsive demand (Borenstein, 2002).

The average price in the summer of 1999 was twice as high as it was in the previous two summer seasons. The market imperfections, including the market change from cost-based offer to market-based offer in April 1999, were major reasons (Mount, 2000; Mansur, 2001). Deregulated power price in Alberta has a long memory and is subject to clustered price volatility. The short term forecasting performance, for example, by the most-frequently-used mean reverting models or time varying and jump diffusion models, is poor (Atkins and Chen, 2002). Although low power price is an encouraging sign, Australia suffered erratic patterns of price spikes that lead to high price volatility (Monut, 1999; Li and Flynn, 2004b). Fabra (2003) empirically analyzed the Spanish power prices in 1998 and found that firms alternated between collusions and price wars which were more likely to start when the market share of the major power generator, Iberdrola, decreased and when all firms' market revenues increased.

Price caps are a matter of some controversy in terms of impact on a market. Many markets have imposed them to protect consumers, who often are unaware of the price of power at time of consumption. However, some blame price caps as another important driving force to high price volatility and huge price spikes. Imposing a price cap was originally designed by regulators to avoid "price-spike" problems and protect power consumers from the loss from high prices. However, price cap can distort incentives for competition which is the blueprint of deregulation, and sometimes may even aggravate the price-spike problem (Hughes and Parece, 2002). Stoft (2000,2003) contends that the California experience shows that price caps drive suppliers away from the market, thus raising prices. There is evidence that price volatility in Britain increased significantly during the period of the two-year price cap, and generators with market power might have had an incentive to create price volatility in the spot market to benefit from the contract market (Robinson and Baniak, 2002).

A.4.2.2 Price Comparisons

Most empirical studies thus far have focused on individual markets; however, there are limited studies comparing deregulated power prices between power markets.

Wolak (1999) compared annual average power prices in four markets, including England and Wales, Norway, Victoria Australia, and New Zealand, and found that power prices are significantly different from jurisdiction to jurisdiction. The major cause of the difference is the exercise of market power. Electricity supply industries with a large component of private company participation in the generation markets tend to have more volatile prices. Electricity spot markets with mandatory participation also tend to have more volatile prices than markets with voluntary participation.

Another comparison between Britain, Scandinavia, Australia, and California, related the price differences to the status of markets, including market structure and the state of deregulation (Masson, 1999). A comparative analysis of price volatility in PJM with New England and with California (Mount *et al.*, 2000), where the price volatility was described by a stochastic Markov regime-switching model, found that the main differences among markets were the levels of price mean in the high-price regimes.

A broad comparison of the impact of regulatory reforms on price was conducted by Steiner (2001) based on 1986-1996 panel data of 19 OECD countries. Hattor and Tsutsui (2004) extended this comparison to 1999. Both investigations found that expanded retail access is likely to lower industrial power price, and increase the price difference between industrial and household consumers. The unbundling of generation from T&D segments, and the introduction of wholesale spot markets did not necessarily lower the price and may possibly have resulted in higher price.

A.4.3 Price Modeling or Forecasting

Under regulation, the cost-base pricing made price forecasting trivial. Historically, electric utilities used structural models to arrive at expected cost and power price is cost-based. The models are good for understanding features of power cost. However such cost-based power prices do not accurately forecast the future price, which depends on future decisions about generation. Moreover, traditional production-costing models do not represent the multi-commodity electricity market, ignore transmission constraints, and neglect price volatility (Masson, 1999; Deb *et al.*, 2000; Niemeyer, 2000). Many have tried to develop forecasting models for deregulated markets.

A.4.3.1 Empirical Models

Many different approaches have been studied to model deregulated power price. Relating power price to load and paralleling price-forecasting models of other commodity, such as gas, oil, or even stock, are the beginning stages of forecasting.

Load forecast an existing technique in the power industry. For general introduction see, for example, Gross and Galiana (1987). For the most recent results see, for example, Khotanzad *et al.* (2002), and Huang and Shih (2003)). Load is helpful in understanding, in part, price behavior (Pilipović, 1998; Allen and Llić, 1999; Weron, 2000; Bunn, 2000), but not enough in forecasting price. The uncertainty in load due to forecasting errors will be amplified into high price volatility (Mount, 1999). Wolak (1999) found that the ability of time series models to predict price is low at times of high load and the ability to model price varies between markets. A recent work (Vucetic *et al.*, 2001) explored the ability of load to predict power cost in California in the period of April 1998 to September 1999. One interesting finding was that if price is modeled against load in a third order polynomial model, then additional data on the hour and day does not significantly improve the predictive ability of the model. Load therefore contains substantially the same diurnal variance as price, and the limited correlation between price and load indicates that other factors are significant driving forces of price.

It appears that when baffling deregulated power prices comes to power players, people instinctively rely on the existing price models of other commodities to understand and even model power prices. Among a set of models describing price, the Brownian motion model, also known as a Wiener process, and mean-reverting models are dominant. Brownian motion is in fact a discrete-time random walk, by which price change over a short time can be expressed as two components a drift and deterministic term that is a stochastic (or random) contribution to the change in the price. A mean-reverting model is good at capturing the negative autocorrelation of price change and spot price, which is a major character of the deregulated power price (Pilipović, 1998; Deng *et al.*, 2001; Allen and Llić 1999).

Price volatility models, roughly, have two categories: standard constant volatility model and stochastic volatility model. Black and Scholes (1973) described volatility as a constant over time. For power in deregulated markets, and indeed for many other energy commodities and assets, historical price volatility data strongly indicated that the constant volatility model does not apply. High spikes in power price, which can be driven by external events, such as abnormal weather events, generator outages, and institutional features of particular markets, and by gaming behaviors, occur from time to time. Constant volatility models fail in capturing the affect of price spikes. Stochastic models, for example, Markov jump, describe price volatility by two parts: a constant mean return and a random return shock, which is conditional on previous information (Deng, 1998).

A.4.3.2 Time Series Models

Another dominating branch of modeling price and its volatility is the family of time series models, including AR, ARIMA, and ARMAX for price, ARCH, GARCH and EGARCH for price volatility[1]. These models have achieved good results in forecasting power load and the price of other commodities (for example, see Hagan and Behr, 1987; Gross and Galiana, 1987; Huang and Shih, 2003).

Attempts to parallel time series models in forecasting power price have been made. For example, a simple AR model for the Norwegian system (Fosso *et al.*, 1999), and an ARIMA model for Spain and California (Contreras *et al.*, 2003) are used to predict power prices. The ability of traditional time series models in forecasting daily and weekly power price was discussed (Nogales *et al.*, 2002; Contreras *et al.*, 2003). Different stochastic switching price regimes were identified in PJM (Mount et al, 2000), and California (Vucetic *et al.*, 2001). The market-oriented switching model is capable of capturing the spike right, does an adequate job for price calls but a poor job of pricing outs (Davison *et al.*, 2002).

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[1] Empirical time series model: AR stands for Auto Regressive modeling, ARIMA for Auto Regressive Integrated Moving Average modeling, ARMAX is a variation of ARIMA, and ARCH for Autoregressive Conditional Heteroskedasticity volatility modeling, GARCH for General ARCH, EGARCH for Exponential GARCH.

Multivariate GARCH model, in which power price volatility is affected by the history of its own and other related factors (for example, gas, oil and weather etc), can incorporate cross-market information and improve the estimation (Kroger and Sultan, 1993).

However, the models in ARCH family are good at capturing price volatility, for most commodities, but not very good in modeling power price volatility, which is evident in the comparison between different models (Duffie *et al.*, 1999). Based on power prices in California, a comparison of forecasting abilities found that the traditional financial time series models could not capture the nature of deregulated power prices and offered a poor representation (Knittel and Rebutters, 2001).

A.4.3.3 Other Approaches

In addition, many other approaches have taken pieces of the challenge in price forecasting (Fu and Nguyen, 2003). Artificial neural networks (ANN) have been proposed (Wang and Ramsay, 1998; Bastian *et al.*, 1999). In particular, Szkuta *et al.* (1999) gave light on short-term forecasting of system prices using a three-layered ANN with back-propagation; the results from the Victoria power market have daily mean errors around 15%. Prediction and confidence interval estimations by a cascaded ANN approach were tested, based on MCP prices in New England, and proved that the cascaded ANN approach is accurate and computationally effective (Zhang *et al.*, 2003). The Monte Carlo method tackles the difficulty of power price prediction (Putney, 1999). A conceptual framework for designing price-forecasting approaches shows an emergence of comprehensive methodologies of predicting power prices (Angelus, 2001). Some structural models forecasting long-term power price volatility for valuation of real power options (Niemeyer, 2000), or simulating price volatility (Deb *et al.*, 200) are suggested as more accurate ways to quantify power price risk.

In reality, no power price forecasting model to date works well in forecasting price. By its nature, power price has high volatility and high price spikes. In addition all statistical models are based on an assumption that the data has a normal distribution. The assumption is inappropriate for the deregulated power prices. Instead, power prices are skewed distributions with large kurtosis. For these reasons how to best model spot deregulated power prices remains open.

A.4.4 Market Power

Market power, another major concern in deregulated power markets, is the ability of an electricity supplier to raise prices profitably above competitive levels and maintain these prices for a significant time. Market power exists in two forms – horizontal and vertical. Vertical market power may occur when a firm controls two related activities, for example, in the power industry, one firm controlling both generation and transmission has the potential to exercise vertical market power. Unbundling the traditional power utility by separating generation from the T&D system (via ISOs and RTOs) is designed to eliminate the potential for vertical market power. Horizontal market power may occur when a firm controls a significant share of the market. In the electric power generation segment, one firm controlling a significant share of electric generation capacity in a particular region, has the potential to exercise horizontal market power (Liu *et al.*, 2003; Lesicutre *et al.*, 2003). Backerman *et al.*, (2000) have used experimental economics to show that generators can capture congestion rents and make excessive profits. Simulation models have been used to show that participants can exploit opportunities for market power (Bernard *et al.*, 1998; Bunn, 2003).

Electricity suppliers exercising market power to force consumers to pay higher electricity prices than they would pay in a market characterized by true competition is evident in many deregulated markets. Britain has been criticized for the market power of two-generation companies, National Power and PowerGen, who operate the majority of the generation capacity (Masson, 1999; Wolak, 1999), and have potential for market power (Green and Newbery, 1992). Investigation of the possibility that the volatility of spot prices is strongly affected by the power contract markets suggests that generators with market power may have an incentive to create volatility in the spot market, in order to benefit from prices in the contract market (Robinson and Baniak, 2002).

High levels of power prices in California were attributable, in part, to some power suppliers exercising their market power (Wolak, 1999). Based on hourly data on price, cost, and output in the first years, Puller (2002) found strong evidence that utility firms do not behave as price takers but rather the exercise their market power. Power prices in California since 1998 were higher than their estimated marginal cost, particularly during summer, and there was an increase in the market power of generators (Borenstein *et al.*, 2002). The enormous increase in the amount of market power exercised, due to a substantial increase in the amount of unilateral market power possessed by each of the five large suppliers in California, in June 2000, was one of the main driving forces of the California 2000-2001 crisis (Borenstein and Bushnell, 1999; Joskow and Kahn, 2001; Wolak, 2003b).

Nord Pool in Scandinavia is often described as a success both technically and economically, and may be a different example of market power. Certainly, spot price and price volatility with infrequent spikes and reasonably strong reverting tendencies are an indication that the competitive power market is functioning well. There are more than 100 generating companies in Scandinavia. Two companies, the state-owned Statkraft and the private Swedish generator Vsttenfall, have over 50% of the local market share and dominate in generating capacity. Since both companies have close ties with government, it is thought that they may be politically motivated to ensure the stability of the deregulated power price (Masson, 1999; Flatabø *et al.*, 2003). Other factors, including too many independent and small sectors on supply side, and a large share of hydropower on the market are likely to mitigate market power (Halseth and Olsen, 2000).

Other studies that show market power as one of major reasons for spikes and volatility of power price include: Brennan and Melanie (1998) and Mount (1999) on Australia; Ocana and Romero (1998) and Fabra (2003) on Spain; Mansur (2001) on PJM; and Mount (2000) on three American markets, New England, California and PJM. These studies found that there is a significant potential for market power without countermeasures.

Given the effect of market power on deregulated power markets, especially on the intolerable price level and high volatility, flawed market structures, such as uniform pricing and mandatory market participation, were blamed for favoring the exercise of market power (Wolak and Patrick, 1997; Hämäläinen *et al.*, 1999; Mount, 2000). The market rules governing the price determination, the uniform price auction that is adopted in most deregulated power markets, exacerbates price volatility and aids the exercise of market power (Mount, 1999; Guan *et al.*, 2001; Guan, 2002). A discriminatory price auction is proposed as a better alternative to reduce the responsiveness of price to errors in forecasting total load (Mount, 1999; Rassrnti *et al.*, 2001). Wolak (2000) derived a bidding behavior model and applied it to the first three-month price data in Australian National Electricity Market (NEM). His analysis illustrated the sensitivity of biding strategies to the amount of hedging contracts and suggested that financial hedging contracts might be an effective means to mitigate market power.

Price caps are regarded by many as a partial remedy for market power and have been adopted in many markets, for example, in California (Soft, 2000; Mount *et al.*, 2000), PJM (Mansur, 2001), Alberta (Lawrence and Sanderson, 2001; Woo, *et al.*, 2003), Ontario (Chan, 2002), and Australia (Moran, 2002; Beder, 2003; Phunnarungsi and Dixon, 2003). Some attribute the public tolerance of deregulation to price caps, since most small consumers do not have a mechanism of knowing the price of power at time of use, or of being billed on a time of use basis. However price caps have been criticized by some for causing price spikes, since it limits the generators' market power, but impels the generators to increase risk premiums in the contract market to maintain revenue. The imposition of price caps with the coordination and the long-term consequences distorts incentives and sometimes aggravates the price-spike problems they intend to solve, which in turn, violates the merit of competition, and will hinder long-term economic validity. Moreover, with price caps, the cost of power cannot be rightly conveyed to consumers, and price caps do nothing to stem future demand, as consumers have no incentive to curb their power usage. Government intervention slows down the addition of new generation and also cause decreases the ability of the market to bring existing non-running generation online, e.g. drives suppliers away from the market (Stoft, 2000; Robinson and Baniak, 2002; Hughes and Parece, 2002). Regardless of the merits of this debate, many governments adopted price caps "on the fly" to quell strong reaction against deregulation, including California, Alberta and Ontario.

Market power among power generators is likely to be a more serious and ongoing concern than anticipated. As a result, the roles of transmission capacity and demand-side price responsiveness are becoming more important than previously suggested. Until real-time metering is more widely available, making real-time responsive demand feasible on a significant scale, price caps will likely remain unavoidable.

A.4.5 Demand Side Management (DSM)

DSM includes load management and strategic conservation. The objective of DSM technologies in the power industry is to reach its full market potential, to stimulate the power industry to function more efficiently while adding value to the power industry investment for customers. For a general discussion of DSM in the electrical industry, see, for example, Caves *et al.* (2000), Hirst (2001), Covino (2003), and Kirschen (2003).

Throughout the history of the power industry, DSM is not new for the generation side. Historically, DSM is the process of changing consumers' consumption activities to reduce the cost of generating power for the power generation side. From the regulatory perspective, the DSM program can be broadly classified into two categories, passive and active. Passive programs, such as high-efficiency appliance substitution programs, save power according to the consumer's consumption patterns. Through the utilization of active DSM programs, such as direct load control (DLC) and dispatchable special contract load control, utilities can control DSM resources to meet the capacity requirements. Although passive programs account for the majority of demand-side resources, they are considered to be less reliable than active programs since the utility cannot control the timing or amount of load management (Eaton and Boske, 2000).

As the power industry has been liberalized and deregulated, DSM has become more important for power consumers. Utilities that once responded to increasing power demand by building more new generation stations now are trying to satisfy a portion of new power demands through DSM or purchased power. Power consumers, as they become exposed to more volatile power prices, face the possibility of a demand change, especially during system peaks, and may decide to manage their demand and shape their consumption according to the price signals to minimize the cost of power (Patrick and Wolak, 1997).

Wholesale competition in power supply can only benefit consumers when there is open-access retail competition and responsive demand through ubiquitous real-time metering, and RTP gives consumers greater incentive to reduce their consumption at peaks, which would in turn lead to lower overall power costs. A more active participation of demand side would make power markets not only more efficient and competitive, but also promote a more optimal allocation of economic resources (Faruqui and George, 2002). By a demand-response mechanism customers are able to react to high prices without interfering with the normal supply-side corrective markets process, such as investment into additional capacity; and would make deregulated power markets more efficient and competitive (Rosenzweig *et al.*, 2003; Kirschen, 2003).

Moreover, it is a belief that handicapping the demand side of the markets will increase the likelihood of the exercise of market power (Hämäläinen *et al.*, 1999; Borenstein, 2002; Rosenzweig *et al.*, 2003), prevent forced outages (Neenan *et al.*, 2002), downward the pressure on market price and price volatility (Rassenti *et al.*, 2001), especially during the initial transit period of deregulation (Wolak, 2001; Borenstein, 2002). The recent California experience made painfully clear that introducing competition in supply side, while shielding the demand from literalized prices seriously distort the market (Cares *et al.*, 2000).

Demand response is a key factor in dynamic RTP. The limited demand response is caused by two major reasons. Legislative and regulatory barriers deriving from jurisdiction efforts to protect retail consumers from the vagaries of competitive markets have slowed the mitigating price signals to consumers consumption through DSM and hindered a move toward price-responsive market structures (Hirst, 2001). Market designers should recognize that the current rate structure, e.g. uniform pricing, provides consumers with little understanding of the underlying cost of the power they consume, and thus provides significant insensitivity to price on the demand side (Guan *et al.*, 2001; Guan, 2002). Moreover, the approval of price caps can thwart demand side participation (Stoft, 2000; Kirschen *et al.*, 2001; McKinsey & Company, 2001). Price responsiveness is significantly higher for large commercial and industrial customers than that for residential and medium sized industrial and commercial consumers. The technological reason for this is the lack of real time meters (or limited use of metering) available at the residential and medium consumer level. Adoption has been slowed down by other factors including communication, computing, and control technologies (Hirst, 2001; Goldman *et al.*, 2002).

Much existing DSM focuses on the generation side limiting load (Eaton and Boske, 2001). Since deregulation, especially with experiences of some price volatile periods in markets, more businesses, both from generation and consumption sides, are participating in the DSM program (Lawrence, 2002; Lawrence and Neenan, 2003). Analysis of DSM in a competitive European market revealed different DSM activities should be arranged for different customer groups (Didden and D'haeseleer, 2003). DSM is about to undergo a generational shift, from a regulatory-driven mechanism to solve defined social objectives, to a device to improve the competitive advantage of utilities and others providing energy services to end users. The traditional DSM program needs to be improved to make it more attractive to and beneficial both to electricity consumers to providers (Gehring, 2002). A good prospective participant often has previous experience with some forms of load management program, but any lack of experience can be overcome through appropriate education (Neenan *et al.*, 2003).

DSM can be thought of as occurring in two stages. The first, which is called "easy load" in this study, is power consumption that requires little advanced notice, thought or planning to interrupt; when the price is high, this kind of load is shut off. This first stage of DSM typically comes from large power consumers and is available in any market. The greater the tendency of a market to experience high price spikes, the more vigorous the search for easy load. Beyond easy load is a second stage of DSM that requires more sophisticated planning, for example, of production processes; which is called "planned load" in this study. This second level of DSM is only realizable in markets where consumers believe that planning can have an expected positive outcome. The less comprehensible and consistent power price patterns are, the less likely planned load will emerge. Examining the time effect on power price yields the consistency and comprehensibility of power price, which serves as an important indicator for consumers contemplating DSM, as discussed in detail in Chapter 5.

A.5 Summary

An introduction to the electricity industry and its deregulation is given. Changes and experiences of individual deregulated markets are exemplified. Literature on the market risk, including power pricing, price behavior and volatility, price modeling, market power, and DSM, are reviewed.

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APPENDIX B POWER PRICE DATA

This section defines the deregulated power data used in this study, including the data collecting criteria, data cleaning methods, and an elementary data analysis.

B.1 Data Collection Criteria

In this research hourly or half-hourly power prices were collected from 18 deregulated power markets, as shown in Table 2-6, Chapter 2, including five regional markets in North America, five regional or national markets in Europe, and eight regional markets in Oceania (Australia and New Zealand). Brief introductions to the selected markets were given in Section A.3, Appendix A, whereas detailed information about each market can be found in the specific web sites, identified in Table 2-6. Table 2-6 also lists the data source and associated currency used in each market. The price of power is measured by local currency. All markets (except Spain where the price unit used is Euro cent per Kilowatt hour (KWh)) use currency unit per Megawatt hour (MWh) as the price unit. The following criteria were used in selecting deregulated power markets and collecting power data.

Criterion 1: Deregulated wholesale spot markets.

Power price data was collected from deregulated wholesale spot markets. What is referred to as the spot market is not identical for each market, but rather is the price that the individual market identifies as the predominant price of power. For example, in Alberta and Australia an hour ahead bid is the predominant power price, while in PJM the predominant price is set by a day ahead bid price; PJM has a small hour ahead market that serves as a clearing market, primarily for adjustments in day ahead estimated volumes. Bilateral-exchange-based markets, such as the market in Texas, have emerged at a later stage of the deregulatory process and are relatively new; they are not included in this research.

Criterion 2: The extent of deregulation in power markets.

The power data was collected from the point in time when a majority of the power traded in the power market was deregulated or competitive. In practice, deregulation is often phased into markets that have historically been regulated, and during transition periods markets are buffered by holdover arrangements. In particular:

- The Province of Alberta established a central power pool, the PPOA, through which all power was marketed as early as 1996, but major utilities had legislated arrangements in place (effectively legislated hedges) that served, in effect, as ongoing regulatory mechanisms, until January 1, 2000, and small business and residential consumers were not introduced into the market until January 1, 2001. Note that from 2002 on, the power market in Alberta has been operated by the Alberta Electric System Operator (AESO)[1], which is the successor to the PPOA and took over the dispatch and transmission administration roles. In this study the acronym PPOA is used to refer to the Alberta power market.

- PJM, which coordinates the movement of power in all or parts of Pennsylvania, New Jersey, Delaware, Ohio, Virginia, West Virginia, and the District of Columbia in the eastern US, first operated in 1997 and had cost based bidding until April 1999, when full deregulation of bidding occurred.

- The market in Germany, the LPX, has been involved in wholesale power trading since June 2000, when physical fulfillment was established, and later merged with and adopted the European Energy Exchange (EEX) in 2002. However over 85% of total volume traded in the LPX has been marketed through either future markets or regulated channels. Again, in this study the acronym LPX is used to refer to the deregulated power market in Germany due to the short history of the merger.

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[1] Available online at http://www.aeso.ca

- The Norwegian power pool, established in 1992, was renamed the Nord Pool when it was integrated in to the Swedish power market in 1996. The Finnish power market El-Ex, built in 1996, merged with the Nord Pool in 1998, and formed the first multi-national power market. From January 1997 on, the fee for changing power provider has been eliminated.

Because power price during transitional periods has an unknown relation to prices after full deregulation, this data was excluded from the data sets.

Collected power price data from all except three markets extends to the end of 2002. The power markets in Southern and Northern California were suspended from February 2001 due to the collapse of credit of the ISO (independent system operator) during the California power crisis. The most recent power data in Britain is for February 2001, after which a bilateral market emerged as the predominant market for power sales, with only a very small spot market for clearing volume discrepancies. British data for January and February 1998 were unavailable.

Criterion 3: Validity of deregulated power data.

All deregulated markets studied had a history of two years or more. Markets with short-term deregulation history and limited deregulated power prices do not provide sufficient data to draw conclusions. For example:

- The deregulated power wholesale market in Ontario, Canada, operated by the Ontario Independent Electricity Market Operator (IMO)[1], was put into operation in January 2002, following which the wholesale power prices rose sharply in the summer of 2002. Ontario faced a consumer revolt even before the onset of deregulation and price caps were instituted for all small power consumers, and the power market reverted back to regulation again (Chan, 2002).

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[1] Available online at http://www.theimo.com/imoweb/role/info.asp.

- After years of effort, the deregulated power market in Texas, operated by the Electric Reliability Council of Texas, Inc. (ERCOT)[1], opened on July 31, 2001; a full retail component began on January 1, 2002 (Zarnikau, 2004). The market in Texas, however, is primarily a bilateral market where buyers and sellers can engage in power transactions independently without having to necessarily interact through the pool (Sundharajan *et al.*, 2003).

Criterion 4: Availability of power data.

One notable region not represented in this study is Latin America where repeated efforts to obtain power price data from local markets failed. Countries in Latin America, including Chile, Argentina, Uruguay, and Brazil, began large-scale privatization of their electric power industries, which is regarded as a prelude of deregulation (Spiller, 1996), back in the 1990s. In Asia the foundation for power deregulated has been laid and these nations are becoming more active as deregulation is evaluated with and more foreign utility companies enter the marketplace.

Table 2-2 shows the detailed information of the collected hourly or half-hourly power prices. The time interval, e.g. hourly and half hourly, is different between markets. Markets in North America and Europe (except Britain) release power price data on an hourly base; markets in Australia, New Zealand, and Britain release power price data on a half-hourly base. The beginning time in each market is different depending on the date when a market was functioning. The earliest operated market is the Nord Pool in 1992, whereas the latest operated market is the LPX in Germany in June 2000. The total number of collected price date points is over one million. Power load data are available in all markets except New Zealand. Some additional data, e.g. excess capacity, are available in Britain.

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[1] Available online at http://www.nerc.com/regional/ercot.html.

B.2 Data Cleaning Methods

As received, the raw power data contains some errors, consisting missing data, duplicate data (i.e., multiple data points for a single time period), and questionable data (i.e., negative or zero value of price). One source of the duplicate and missing data is the time switch adopted in a specific local jurisdiction. For example, the power prices from Alberta in 2000 contain one extra datum point at 2 A.M. on October 29 and one missing datum point at 3 A.M. on April 2. This redundancy and absence of data is due to the time switch between the Daylight Saving Time and the Standard Time[1]. A very small set of data had negative or zero values: there were removed from the data set, i.e. treated the same as missing data. It is possible that zero price bids reflect "must run" plants; it was not possible to confirm whether this was the condition at the time of a recorded zero price, or whether the value was an error in recording. Because of the very small amount of questionable data, the impact of the decision to treat this data the same as missing data does not have a significant impact on the results of this study.

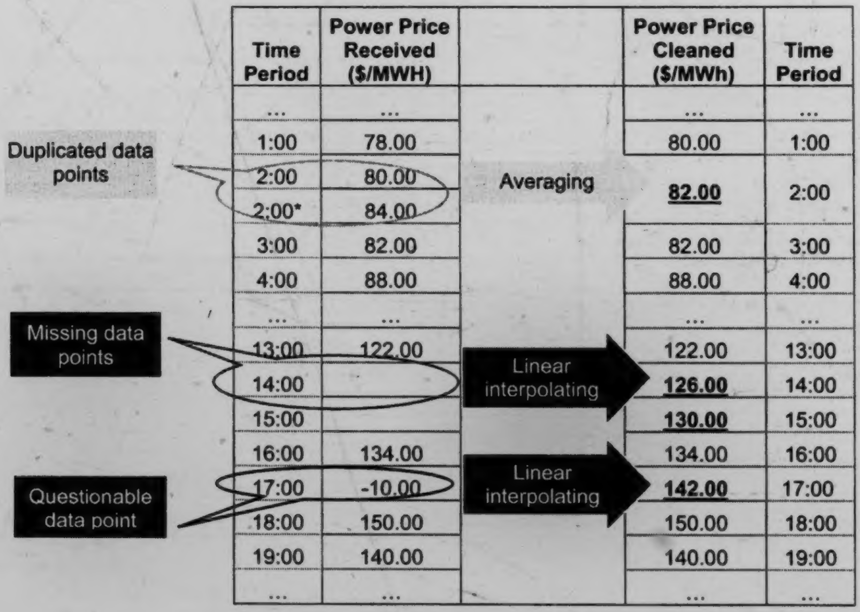
All the errors contained in raw data have been cleaned. Missing and questionable data points were either filled in with or replaced by linear interpolation; duplicate data points were consolidated by averaging. Table B-1 shows examples of the three types of data errors and the corresponding data cleaning techniques used:

- The duplicate price data, e.g. two data points at 2 A.M., marked at by 2:00 and 2:00*: a new power price $82 per MWh averaging $80 per MWh and $84 per MWh is generated and inserted as a cleaned power price at 2 A.M.

- The missing data at 2 P.M. and 3 P.M., marked by 14:00 and 15:00: new power prices $126 per MWh and $130 per MWh are generated by linear interpolations and inserted as cleaned power prices.

- The negative price –$10 at 5 P.M., marked by 17:00: a new price $142 per MWh is generated and replaced as a cleaned price.

Table B-1 Examples of Power Price Data Cleaning Methods


Duplicated data points
Missing data points
Questionable data point

Time Period	Power Price Received ($/MWH)		Power Price Cleaned ($/MWh)	Time Period
...	...		...	...
1:00	78.00		80.00	1:00
2:00	80.00	Averaging	**82.00**	2:00
2:00*	84.00			
3:00	82.00		82.00	3:00
4:00	88.00		88.00	4:00
...	...		...	...
13:00	122.00		122.00	13:00
14:00		Linear interpolating	**126.00**	14:00
15:00			**130.00**	15:00
16:00	134.00		134.00	16:00
17:00	-10.00	Linear interpolating	**142.00**	17:00
18:00	150.00		150.00	18:00
19:00	140.00		140.00	19:00
...	...		...	...

The 4th column in Table B-1 shows the power price data cleaned. Note that, to simplify computation, all power prices in this example are rounded to integers.

B.3 Elementary Data Analysis of Power Prices

B.3.1 Variations in Power Prices

Power prices vary widely in deregulated markets; markets that are isolated from each other by geographical barriers or transmission limitations cannot interact during periods of high prices. The unique fact that electric power is not storable makes keeping a balance, at all times, between generation load and consumption demand within a market, critical. Technical aspects, such as costly

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[1] In Alberta the Daylight Saving Time begins at 2:00 A.M. local time on the first Sunday in April, on the last Sunday in October areas on Daylight Saving Time return to Standard Time at 2:00 A.M.

long distance transportation, and bottlenecked transmission capacities, and the effects of weather and climate change, plus inelastic responsiveness of demand from consumers, have a dramatic influence on power price. It is not unusual for a power consumer to face both significant daily variation in price and large variations in average price between days in a deregulated market, and power consumers in different markets face different price variation.

Deregulated power markets show different patterns of power prices. As shown in Figure 2-1, in Alberta, high price swings within a day are evident. For example, power price swung from the lowest value CAD6 to the highest value CAD998 per MWh in the course of the day on August 18, 2002, and from 1996 to 2002 power prices could change, on average, from the lowest value of CAD30 to the highest value of CAD180 per MWh. However, power price level and variation have both changed over time. The power price level and variation were low and relative stable when the PPOA first began in 1996. In the following two years, power price level increased a little and price spikes happened only occasionally. From 1999, and especially during Fall 2000 to Summer 2001, large price spikes were frequent. Power prices reached the ceiling value of CAD999 per MWh, which is a price cap deployed by the market operator, many times.

Britain had a different history. Price variation has been relatively stable, the level of power price and the price spikes have been not as severe as in Alberta, and a consistent seasonal pattern has emerged. In Scandinavia, power prices show an obvious periodical pattern and the market is not characterized by price spikes. In New Zealand, power prices are relatively stable and less periodic, but occasional price spikes are evident and tend to be clustered. Power price data in these three markets are also shown in Figure 2-1. The same data for the other ten markets are shown in Section 2.8.2, Chapter 2.

Figure B-1 shows the coefficient of variation (CV), e.g. the variation divided by the mean of a data set, of power prices in each market. Power prices in Australia have the largest CV, with all the four markets displaying a CV greater than three. Markets in North America, plus the Netherlands have intermediate price variations with a CV over one, while all other markets see low price variation with a CV less than one. In all markets but Spain the price variation is larger than half of the average price.

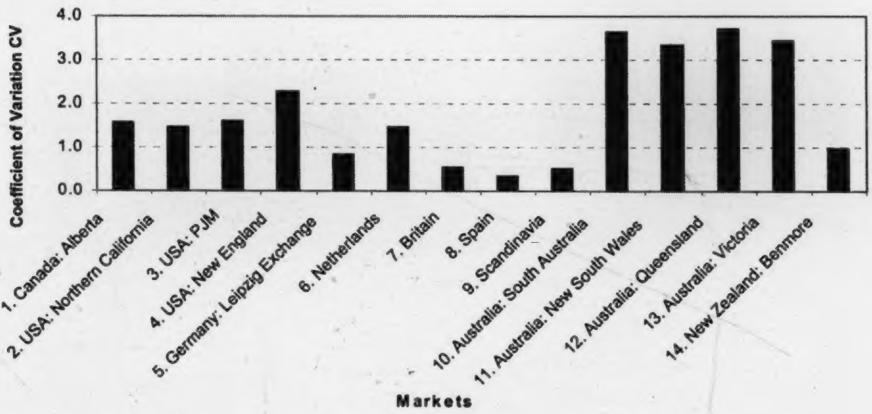

Figure B-1 Coefficients of Variation (CVs) of Power Prices in 14 Deregulated Power Markets

B.3.2 Levels of Power Prices

Figure B-2 shows the overall and annual normalized average power prices of each market. This figure clearly shows that the annual average price did not, as expected, significantly decrease after deregulation in most markets. (The normalized annual power prices in Britain decreased steadily, and has dropped since 1998 in South Australia.) Contrary to expectations, in some markets, for example, the markets in California and Alberta, as deregulation evolved, power prices soared to new price ceilings. These price behaviors forced deregulation advocates to contemplate not only market design but also whether deregulation was suitable for electricity. In this study the exploration of deregulation is conducted by investigating deregulated power price behavior in many markets, which can unveil some aspects and effects of deregulation.

B.3.3 Non-normality of Power Prices

Raw power price data tend to be highly skewed. Table B-2 shows the skewness of power prices in the 14 deregulated markets. It is clear that all but three markets have skewness larger than five, which indicates that the distribution of raw power prices trend to be a non-normal distribution, thus most statistical techniques for modeling price or even measuring price and its volatility, including the variation and standard deviation, which are best used for evaluating data with a normal, or bell shaped, distribution, are not ideal for analyzing raw deregulated power prices.

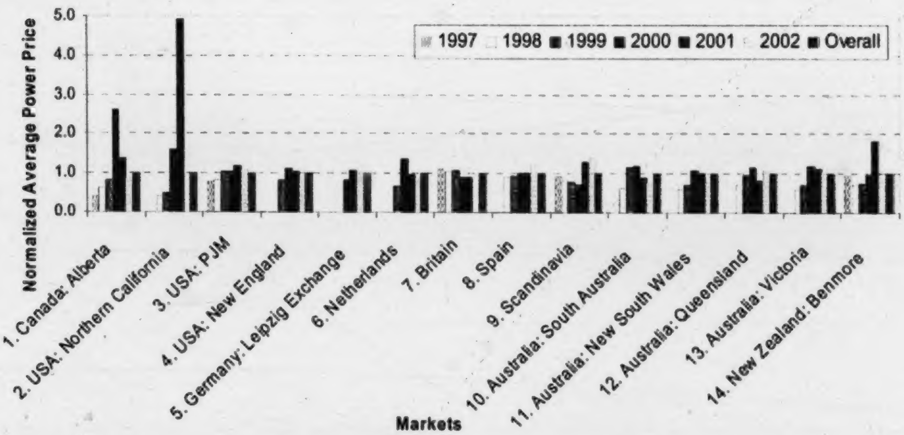

Figure B-2 Normalized Average Prices in 14 Deregulated Power Markets

Table B-2 Skewness of Power Prices in 14 Deregulated Markets

Market	1996	1997	1998	1999	2000	2001	2002	Overall
1. Canada: Alberta	0.9	24.6	11.8	8.8	2.1	3.3	7.8	5.2
2. USA: Northern California			4.0	14.3	2.8	6.2		6.7
3. USA: PJM		3.4	21.0	11.0	8.7	13.5	9.5	16.0
4. USA: New England				12.9	42.8	17.5	24.8	62.9
5. Germany: Leipzig Exchange					2.2	18.5	7.8	18.6
6. Netherlands				0.6	4.7	11.8	7.1	8.2
7. Britain	1.7	1.9	2.5	2.2	1.8	2.5		2.2
8. Spain			0.3	0.0	0.4	0.8	1.9	1.4
9. Scandinavia	0.3	0.8	0.6	1.9	12.8	12.2	2.2	2.4
10. Australia: South Australia			10.6	19.2	18.2	19.6	26.1	20.5
11. Australia: New South Wales			1.7	93.6	30.2	39.0	24.8	36.1
12. Australia: Queensland			3.9	18.6	17.9	19.9	18.3	21.7
13. Australia: Victoria			1.5	64.8	29.4	23.0	27.8	30.3
14. New Zealand: Benmore	4.4	0.2	6.1	0.8	10.7	3.5	1.9	7.0

Deregulated power prices have unique features including 1) the high intraday and inter-day variability; 2) the persistence of high price, i.e., if a high price is observed on one day, there is a higher likelihood that power prices on the following day will also be high; 3) evident and clustered price spikes; 4) periodic behavior in some markets; and 5) non normally distribution. Facing such volatile power prices, a power consumer would benefited by a comprehension of price, which would be helpful in DSM of consumption to reduce the cost of power and in hedging of market risk.

B.4References

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APPENDIX C NORMALIZATION METHODS AND FILTRATION TECHNIQUES

This section discussed issues of normalization and filtration of power prices in greater details.

C.1 Normalization Methods

There are two obstacles in comparing deregulated power prices between markets. The first one is the different currencies used, which can be solved by converting one currency into another based on the exchange rate. Currency conversion will be an increasing computational burden when the time period being studied and the number of markets involved increase; it also raises the question whether anomalies in currency conversion would mask issues of relative power price. For example, as the U.S. dollar fell in value against the Euro, European power prices would appear to drop if reported in U.S. dollars, or U.S. power prices would appear to rise if reported in Euro, and yet from the perspective of the consumer this rise or drop would not be experienced as real. A second obstacle is the existence of different taxation levels and regimes and environment standards between markets, which gives a different long term average price. Consumers relate power prices to an expectation. For example, a power price of $50 per MWh is not unusual in California, which is one of the states with the most expensive electric power in the U.S.; however the same price would be a signal of high prices if it occurred in Texas, which is one of the states enjoying the lowest power price in the U.S. Similarly, the same power price might deliver different signals to power consumers on weekdays and weekends.

The focus of this research is not on the absolute value of power price, but rather on how its variations are shaped by, and in turn shape, human behaviors. To fulfill the objective, two types of normalization techniques are adopted, which eliminates differences between markets of currency and average price, and enables comparison of prices both within a market and between markets. Two types of normalization techniques are adopted including: 1) Normalization of power prices against the overall average price (OAP) in a market. A power price of $30 per MWh in a market with an OAP of $40 per MWh, has the same normalized power price 0.75 as a power price of £60 per MWh in another market with an OAP of £80 per MWh, i.e., both of these two power prices are 0.75 times the associated values of the OAP. This method enables comparison of the levels of power price relative to the OAP between markets, and best illustrates the driving force to shift power consumption from weekday to weekend; 2) Normalization of power price against weekday average price (WDAP) on weekdays, and against weekend average price (WEAP) on weekends, respectively. This method provides a base to compare price patterns between weekdays and weekends within a market, and best illustrates the driving force to shift power consumption from day to evening on either weekdays or weekends. Normalized power prices are unitless.

Table C-1 shows an example of average 24 hourly price data (absolute and two normalized values) for one weekday and one weekend day within a market, respectively. Note that the average second type normalized power price would equal to one for both weekday and weekend.

Several observations emerge from an inspection of Table C-1 and Figure C-1: 1) an informed power consumer in this example market would have an incentive to shift selective power consumption from weekdays to weekends, since, except the early morning hours 1 A.M. to 5 A.M., the price level on weekends is lower than that on the weekdays; 2) an informed power consumer would have incentive to shift selective power consumption from day to night on either weekdays or weekends, however the extent of such a driving force are different between weekdays and weekends.

In Chapters 2, 3 and 4, the extended analysis of power prices in the 14 markets is based on normalized values rather than absolute values of power prices. These two types of normalization methods will be used alternatively. The first type is used for the comparison of the level of price between markets, whereas the second is used for the comparison of price patterns, especially between weekdays and weekends, within a market.

Table C-1 An Example of Power Prices

Hour	Power Price (CAD/MWh)		Normalized Power Price (2nd Type)		Normalized Power Price (1st Type)	
	Weekday	**Weekend**	**Weekday**	**Weekend**	**Weekday**	**Weekend**
1	55.11	61.00	0.50	0.76	0.54	0.60
2	51.87	56.60	0.47	0.70	0.51	0.55
3	49.90	53.87	0.45	0.67	0.49	0.53
4	48.84	52.75	0.44	0.66	0.48	0.52
5	48.74	51.13	0.44	0.64	0.48	0.50
6	53.67	50.74	0.48	0.63	0.52	0.50
7	68.55	52.88	0.62	0.66	0.67	0.52
8	98.27	60.72	0.88	0.76	0.96	0.59
9	117.12	72.33	1.05	0.90	1.14	0.71
10	124.46	81.96	1.12	1.02	1.22	0.80
11	138.55	91.52	1.25	1.14	1.35	0.89
12	144.01	94.02	1.30	1.17	1.41	0.92
13	146.02	96.67	1.31	1.20	1.43	0.94
14	143.73	95.34	1.29	1.19	1.40	0.93
15	150.43	90.44	1.35	1.13	1.47	0.88
16	149.88	90.92	1.35	1.13	1.46	0.89
17	164.64	102.95	1.48	1.28	1.61	1.01
18	190.48	120.25	1.71	1.50	1.86	1.17
19	150.57	111.32	1.35	1.39	1.47	1.09
20	135.27	97.23	1.22	1.21	1.32	0.95
21	139.23	93.67	1.25	1.17	1.36	0.92
22	134.00	101.24	1.21	1.26	1.31	0.99
23	98.87	82.62	0.89	1.03	0.97	0.81
24	65.22	66.47	0.59	0.83	0.64	0.65
Average Price	111.14	80.36	1.00	1.00	1.09	0.79
Average Overall Price AOP	102.35					

C.2 Data Filtration Techniques

Public support of deregulated power markets has been eroded by price excursions, i.e., large price swings and price spikes. One method of identifying the extent to which price spikes are shaping average price patterns is filtering data sets to remove outliers, and comparing results of filtered vs. unfiltered data.

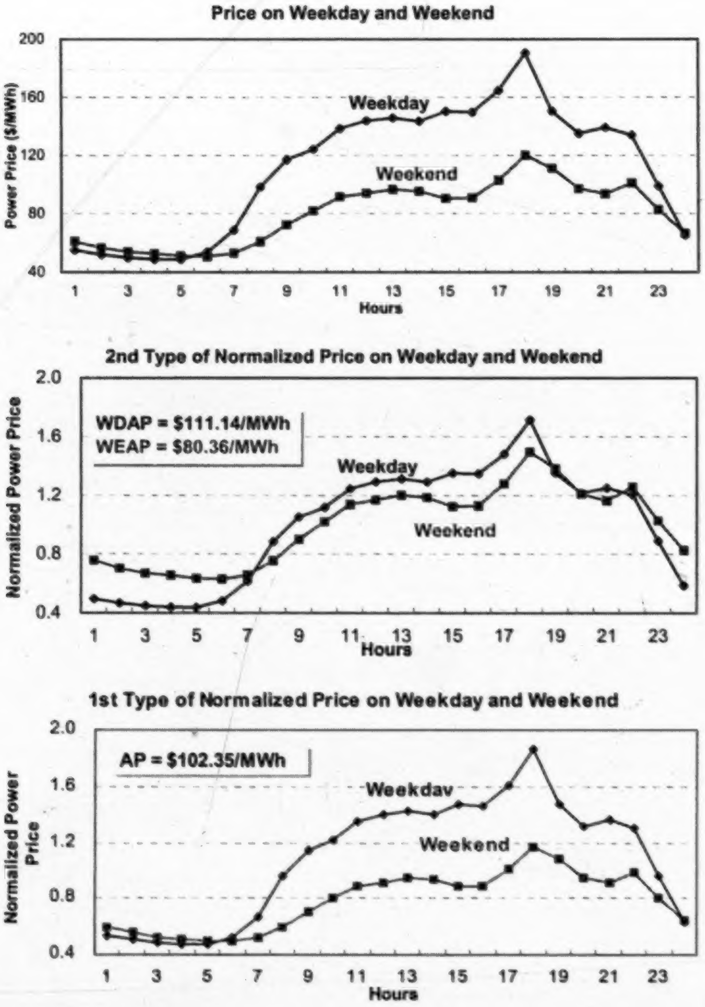

Figure C-1 An Example of Normalized Power Prices within a Market.

Two levels of filtering rate were chosen, 10% and 20%, which are arbitrary and used as a coarse screen of the impact of price excursions on the overall price behavior. For 10% filtration, the 5% of days in the data set on which the lowest price (hourly or half-hourly) occurred and 5% of days on which the highest price occurred are identified, and all (24 for hourly price or 48 for half-hourly price) price data points associated with each of those days are removed from the data set. For 20%, the same approach is adopted to remove the 10% of days with the highest prices and the 10% of days with the lowest prices. Prices are renormalized to the data remaining in the set. Various price behavior indicators, including price ratios and price diurnal pattern, are then recalculated for the filtered data sets to examine the impact of price excursion.

Figure C-3 shows an example of the impact of data filtration on power prices in Alberta. The top panel shows the complete power price data, consisting of almost 50,000 price data points between 1996 and 2002. High price spikes are

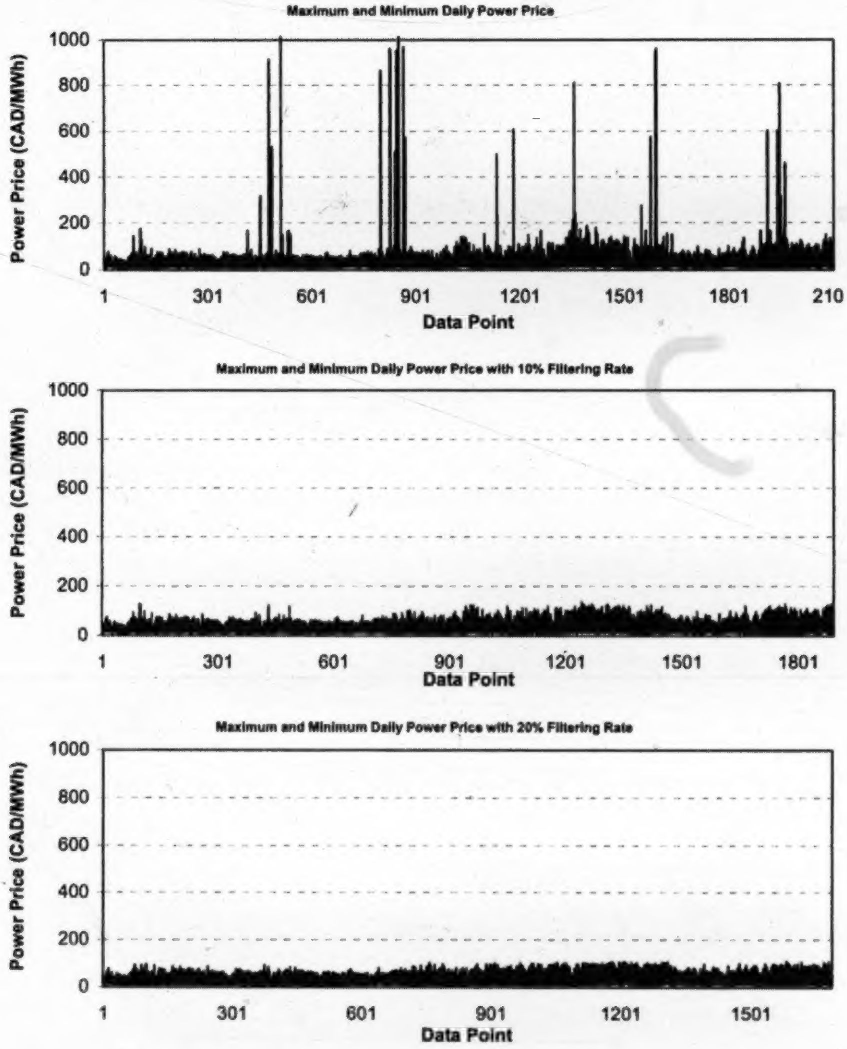

Figure C-2 Effect of Data Filtration in Alberta.

obvious. The middle panel shows the truncated data with the filtering level of 10%. Less moderate price spikes are presented and the highest price significantly reduces from CAD999 per MWh to CAD140 per MWh. After removing 10% highest and 10% lowest data, i.e., the filtering level 20%, shown in the bottom panel, no obvious price spikes are observed, and the highest price is further reduced to CAD105 per MWh. Section 2.4, Chapter 2 will discuss the detailed impact of data filtration on the 14 deregulated markets.

APPENDIX D PRICE VOLATILITY AND PRICE VELOCITY

Electricity, unlike other commodities, cannot be effectively and physically stored: it must be available when needed, and it must be used or delivered when generated; hence delivery and usage must be balanced at all times. This distinguishing feature makes trading of physical electricity dramatically different from trading any other commodity. In some markets, the combination of the inflexibility of generation plants (i.e., generation that must run or is slow to change in output), the variable cost of generation, bottlenecked transmission capacity or congestion, and variable and often inelastic demand leads to wide inter- and intraday variation in power prices, as discussed in Chapter 2, and unavoidable high price volatility in deregulated markets.

This section describes some existing measurements of price volatility, after which deficiencies in the measures for assessing a power consumer's view of price volatility is discussed. An illustration of price velocity and unexpected price velocity as measures of power price volatility is presented.

D.1 Price Volatility

Price volatility is the concept of how price moves relative to time. Generally, the measurements of price volatility are different forms of variation (Pilipović, 1998; Fusaro, 1998). Some statistical approaches for measuring price volatility are summarized as follows:

1) Price range

Price range represents the spread in prices during a specific time period. The price range is typically measured as the difference between the highest and lowest prices during a specific time period. Generally, an increase in the price range typically indicates an increase in volatility.

Parkinson Measure is a transform of price range. If the given period is one day, the Parkinson measure of price volatility is estimated as,

$$Vol(P) = {(\ln(P_{Hi}) - \ln(P_{Lo}))^2}/{4\ln 2},$$

where, *Vol(P)* is the volatility of prices, P_{Hi} and P_{Lo} are daily high and low prices, respectively, and *ln(•)* is the lognormal function.

2) Standard deviation

Standard deviation in average prices presents a measure of the actual price movement over a specific time period. A higher standard deviation represents a greater price movement, i.e., greater price volatility in term of absolute magnitude. Volatility defined as the standard deviation of log returns (as discussed below) measures the magnitude of the percentage changes in price over time.

3) Coefficient of variation (CV)

CV is calculated as the standard deviation divided by the mean value. This measure is a useful comparative measure of price volatility between different markets where prices are reported in different currency, or with different levels of average price, e.g. the CV of power prices in California vs. the CV of power prices in Britain. Section B.3.1, Appendix B discussed the CVs of power prices in the 14 deregulated markets.

4) Returns

A percentage change in prices, rather than in absolute prices, is a measure of price volatility often used as by commodity traders and risk managers. This measure is often referred to as "returns" that reflect the "returns" on investment in a commodity. There are two basic forms of the calculations: price return and price log return. The lognormal form is used in order to create a more normal data distribution. For example, at a specific time period *t*, the return can be calculated by,

$$\mathrm{Re}turn_t = {\Pr ice_t}/{\Pr ice_{t-1}}$$

or on a log normal basis,

$$\mathrm{Re}\,rutn_t = \ln({}^{\mathrm{Pr}\,ice_t}\!/_{\mathrm{Pr}\,ice_{t-1}})$$

Statistical measures of volatility are sensitive to extreme values and are not easy to interpret from the perspective of consumers. In addition, all these statistical measures mentioned above are best used for evaluating data with a "normal", or bell shaped, distribution. Statistical measures to evaluate the normality of the distribution are then important and need to be considered (Pilipović, 1998; Fusaro, 1998). Generally, power prices are bounded by zero on the downside (in some market zero or negative power price are allowed but are extremely rare), and do not have a limit (or have a very high limit compared to average price in markets that have a cap on maximum power price that can be bid) on the upside; the distribution of raw power price data tends to be highly left skewed, as discussed in Section 3.3, Appendix B. Power prices evaluated by a logarithmic form yield a more normal distribution, but are difficult to comprehend from the perspective of power consumers. Therefore, to look at the differences within and between markets in term of price volatility from the perspective of power consumers, a concept of "price velocity" which evaluates the average daily movement of power prices has been proposed and developed in this research.

D.2 Price Velocity –An Measurement of Price Volatility

D.2.1 An Example of Price Velocity

Definitions of two values of price velocity are described in Section 3.8.1, Chapter 3. Figure D-1 shows the relationship between prices and price changes. DVOA gives a sense of the consumer's perception of daily volatility relative to a long term view of price: what is the hourly change in power prices compared to the overall average price within a market? DVOA would more likely influence a consumer's decision to hedge and lock in a long-term price. DVDA gives a sense of the uncertainty a consumer experiences in the buying prices on a given day, i.e., if a consumer buys power at a given hour, how high is the rate of change of price in the subsequent hours of that day? DVDA gives a sense of the short time fluctuation in power prices, which, in turn, will help a consumer in conducting DSM. Note that during a day of price spikes the daily average price is high, then the DVOA would be higher than the DVDA on that day.

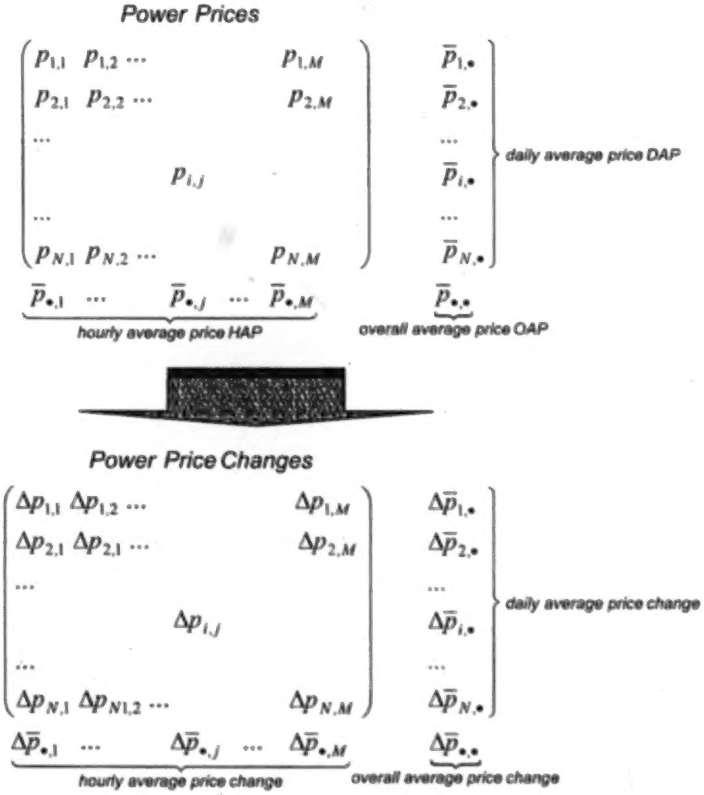
Power Prices
daily average price DAP
hourly average price HAP
overall average price OAP
Power Price Changes
daily average price change
hourly average price change
overall average price change

Figure D-1 Relationships between Power Prices and Price Changes.

Table D-1 shows the average prices and price velocities in Market A and Market B, the two example markets as shown in Table D-2. For example, the DVDA and DVOA of the power prices in Market A are 0.10hr^{-1} and 0.05hr^{-1}, respectively, meaning that the price change on that day, on average, is about 10% of the DAP (which is CAD53 per MWh), and only 5% of the OAP (which is CAD102 per MWh). Thus the prices are more volatile in a short-term view, i.e., within a day, than in a long-term view, i.e., in the total time period Market A has been functioning. It is markedly different from the power prices in Market B: the DVDA and DVOA are 0.02hr^{-1} and 0.03hr^{-1}, meaning the price changes in Market B have no significant difference between short-term and long-term views, and are both less than 3% of either the DAP or the OAP. In addition, the prices in Market B are less volatile than that in Market A, from both short-term and long-term views.

Table D-1 Price Velocity DVDA and DVOA in Market A and B

	Market A (CAD/MWh)	Market B (Kr/MWh)
Daily Average Price DAP	52.53	137.27
Overall Average Price OAP	102.35	80.24
	Market A (hr^{-1})	**Market B (hr^{-1})**
Price Velocity DVDA	0.10	0.02
Price Velocity DVOA	0.05	0.03

Table D-2 Examples of Power Prices in Market A and Market B

Hour	Power Price	
	Market A (CAD/MWh)	**Market B (Kr/MWh)**
1	30.35	128.67
2	27.93	125.64
3	26.52	123.97
4	25.63	122.97
5	25.34	123.4
6	27.64	126.49
7	34.14	132.96
8	45.02	141.65
9	53.19	148.54
10	57.5	147.96
11	63.57	147.32
12	67.64	145.85
13	70.34	143.16
14	68.06	141.9
15	69.55	140.99
16	69.57	140.53
17	75.39	140.98
18	83.51	143.13
19	69.03	142.59
20	62.71	140.58
21	62.96	138.85
22	61.04	138.43
23	48.22	136.12
24	35.94	131.7
Overall Average Price (OAP)	52.53	137.27

The reason that the author has chosen price velocity, which is based on the change in hourly or half-hourly prices, rather than the variance, which is based on the square of the difference between actual and average prices, is that the author believes price velocity more closely parallels the thinking of power customers when they look at power price markets: if a consumer buys power in this period, how is the price going to comparing to the prices of power in past and future periods, and to the expected average price?

D.2.2 Reverse Cumulative Distribution Function (RCF)

One statistic, the reverse cumulative distribution function (RCF), is used to study the price velocity. If *X* is a real-valued random continuous variable, for every real number *x*, the RCF is given by,

$$RCF(x) = 1 - F(x) = 1 - P(X \leq x) = P(X > x),$$

e.g. the probability that variable *X* takes on a value larger than *x*. The RCF describes the probability distribution of a real-valued random variable, completely. For example, a uniformly distributed variable *X* in the unit interval *[0,1]*, its RCF is given by,

$$RCF(x) = 1 - F(x) = \begin{cases} 1, & if\, x < 0 \\ 1 - x, & if\, 0 \leq x \leq 1, \\ 0, & if\, x > 1 \end{cases}$$

Figure D-2 shows the RCF of this uniformly distributed variable. A RCF is monotone non-increasing and continuous from the right, if x is continuous. Furthermore, the equations $\lim_{x \to \infty} RCF(x) = 0$, and $\lim_{x \to -\infty} RCF(x) = 1$ are true.

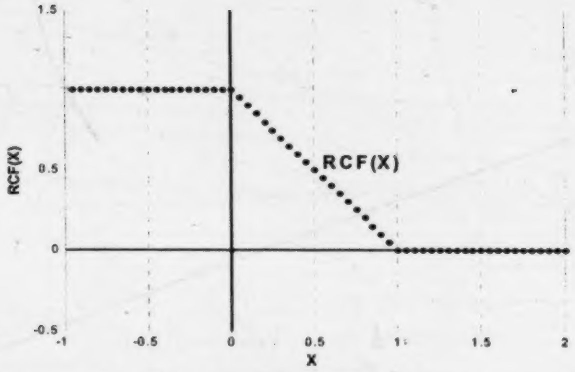

Figure D-2 Reverse Cumulative Distribution Function (RCF) of A Uniformly Distributed Variable.

If X is a discrete random variable containing values x_1, x_2, ...with probability p_1, p_2, ..., its RCF will be discontinuous at the point x_i and constant in between. Figure D-3 gives the RCF of an example of discrete variable shown in Table D-2. The corresponding distribution .function (DF) and the cumulative distribution function (CDF), and are listed in the 6th and 7th columns in the table. From the DF, it can be found that about 20% of the data points locate in the ranges [45, 50) and [95, 100], respectively. By the RCF, as shown in the 8th column, for example, Point A represents about 40% of the data points are larger than 65, where Point B represents about 55% of the data points are larger than 45.

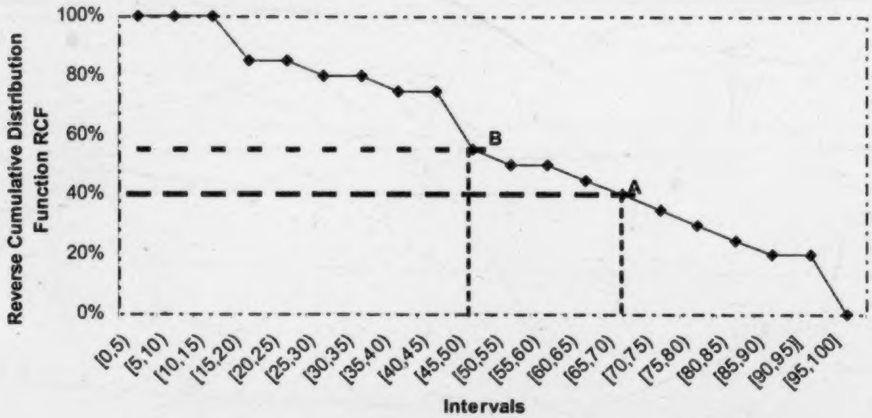

Figure D-3 Reverse Cumulative Distribution Function (RCF) of A Discrete Variable.

Deregulated power prices are discrete. Figure D-4 shows the RCFs of the price velocity DVOA and DVDA of the power prices in Alberta. For example, about 32% of days in which the power price velocity DVOA is larger than $0.2hr^{-1}$, shown as Point A, meaning that in about 32% of the total days the power price change, on average, is larger than 20% of the overall average price OAP in Alberta. Similarly, shown as Point B, there are about 44% of the total days in which the power price velocity DVOA is larger than $0.2hr^{-1}$, meaning that the price change is larger than 20% of the daily average price DAP, on that day. Facing such a high fraction of days with high price fluctuation, an informed consumer in Alberta would like to escape the long-term market risks by hedging.

Table D-3 An Example of A Discrete Variable

No.	**Random Numbers Between 0 to 100**	**Sorted Random Numbers**	**Intervals**	**No. of Numbers in the Interval**	**Distribution Function (DF)**	**Cumulative Distribution Function (CDF)**	**Reverse Cumulative Distribution Function (RCF)**
1	48	19	[0,5)	0	0.0%	0.0%	100.0%
2	54	19	[5,10)	0	0.0%	0.0%	100.0%
3	47	19	[10,15)	0	0.0%	0.0%	100.0%
4	97	28	[15,20)	3	15.0%	15.0%	85.0%
5	19	39	[20,25)	0	0.0%	15.0%	85.0%
6	98	46	[25,30)	1	5.0%	20.0%	80.0%
7	79	47	[30,35)	0	0.0%	20.0%	80.0%
8	81	48	[35,40)	1	5.0%	25.0%	75.0%
9	19	48	[40,45)	0	0.0%	25.0%	75.0%
10	19	54	[45,50)	4	20.0%	45.0%	55.0%
11	87	60	[50,55)	1	5.0%	50.0%	50.0%
12	95	68	[55,60)	0	0.0%	50.0%	50.0%
13	39	72	[60,65)	1	5.0%	55.0%	45.0%
14	46	79	[65,70)	1	5.0%	60.0%	40.0%
15	72	81	[70,75)	1	5.0%	65.0%	35.0%
16	98	87	[75,80)	1	5.0%	70.0%	30.0%
17	68	95	[80,85)	1	5.0%	75.0%	25.0%
18	28	97	[85,90)	1	5.0%	80.0%	20.0%
19	48	98	[90,95)]	0	0.0%	80.0%	20.0%
20	60	98	[95,100]	4	20.0%	100.0%	0.0%

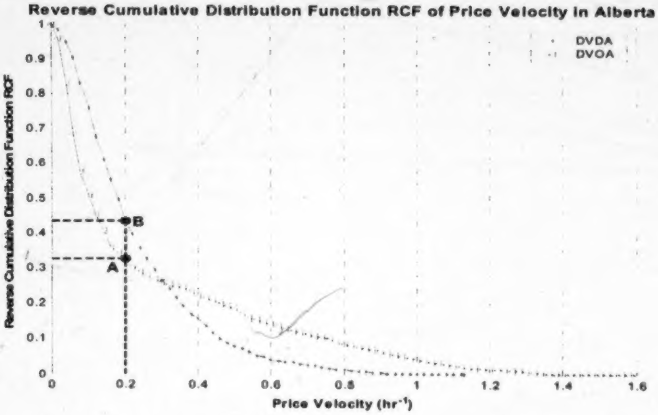

Figure D-4 Reverse Cumulative Distribution Function (RCF) of Price Velocity DVOA and DVDA in Alberta.

D.2.3 An Example of Comparison of Price Velocity between Markets

An example of comparison between three markets: Alberta, Britain and South Australia, by the price velocity DVDA and DVOA is shown in Figure D-5. In a short-term view, i.e., within a day, the price change per hour, on average, exceeding 20% of the DAP is on about 43% (shown as Point A) of the total days in Alberta, whereas 25% (shown as Point B) and 5% (shown as Point C) in South Australia and Britain, respectively. In a long-term view, i.e., the full history of the markets, the price change per hour, on average, exceeding 20% of the OAP is on about 34% (shown as Point D) of the total days in Alberta, and 24% (shown as Point E) and 15% (shown as Point F) in South Australia and Britain, respectively.

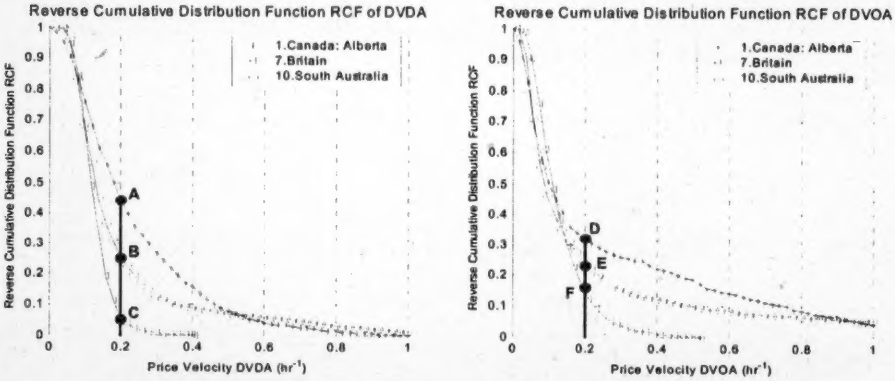

Figure D-5 Reverse Cumulative Distribution Function (RCF) of Price Velocity DVOA and DVDA in Alberta, Britain and South Australia.

A consumer in these three markets can contemplate some financial tools to hedge the risk from the deregulated power market. However the extent of the motivation is different between markets. The expected reward of DSM is highest in Britain and lowest in Australia; the incentive to hedge is highest in Australia and lowest in Britain.

D.3 Expected and Unexpected Price Velocity

D.3.1 An Example of Expected and Unexpected Price Velocity in Alberta

Definitions of expected and unexpected price velocity are described in Section 3.8.3, Chapter 3. Figure D-6 shows the price velocity and the unexpected price velocity in Alberta. Note that the plots are truncated at the price velocity and the unexpected price velocity equal to one. The expected velocity EVOA is 0.11hr^{-1}, meaning the average expected price change per hour, is about 0.11 times the OAP in Alberta arising from the average diurnal price pattern, as previously discussed Chapter 2. The RCF of UVOA is a left shift, about 0.11hr^{-1} along the horizontal axis, of the RCF of DVDA.

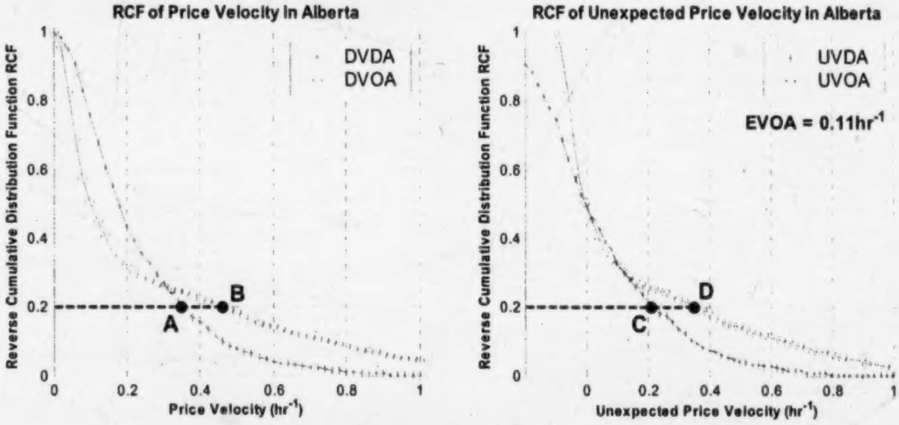

Figure D-6 Reverse Cumulative Distribution Function (RCF) of Price Velocity and Unexpected Price Velocity in Alberta.

Several observations emerge from an inspection of Figure D-6:

- In about 45% of the total days, the price variability is larger than that expected from the average diurnal pattern.

- The price velocity DVDA is higher than 0.36hr^{-1} in about 20% (shown as Point A) of the total days, on which the price velocity DVOA is higher than 0.45hr^{-1} (shown as Point B).

- Subtracting the expected price velocity, the unexpected price velocity UVDA is higher than 0.2hr^{-1} on 20% (shown as Point C) of the total days, on which the unexpected price velocity UVOA is higher than 0.35hr^{-1} (shown as Point D).

D.3.2 An Example of Comparison of Unexpected Price Velocity between Markets

Figure D-7 shows the unexpected price velocity in Alberta, Britain and South Australia, whose diurnal price patterns are shown in Chapter 2. An observation of Figure D-7 reveals that the power prices in Alberta are more volatile than that in South Australia for a higher fraction of days, whereas the power prices in Britain show low volatility.

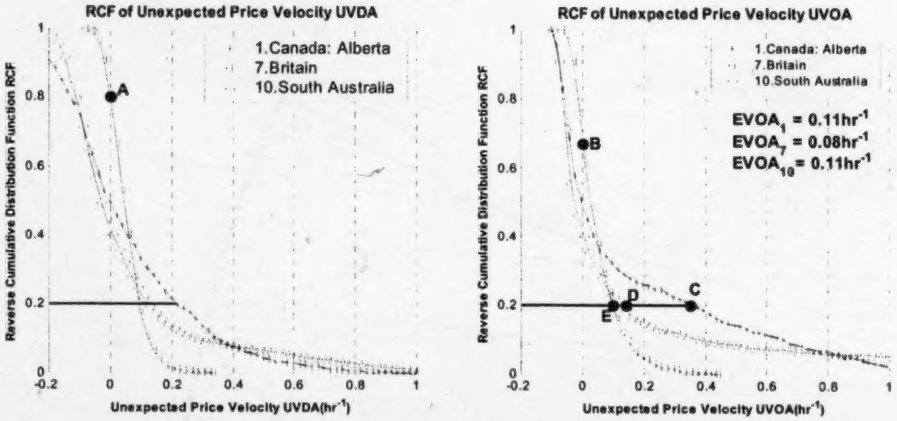

Figure D-7 Reverse Cumulative Distribution Function (RCF) of Unexpected Price Velocity UVDA and UVOA in Alberta, Britain and South Australia.

Price velocity captures the total price movement, and unexpected price velocity assesses the uncertainty of power price. With a comprehensive knowledge of the price history, a consumer can predict and expect some reasonable price movement. The unexpected price velocity may influence the tolerance of power consumers for buying power in the real time spot market.

D.4 References

Fusaro, P.C., 1998, *Energy Risk Management: Hedging Strategies and Instruments for the Energy Markets*, McGraw-Hill, New York.

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APPENDIX E AN APPROACH TO SEASONAL ANALYSIS

This section described the approach to seasonal analysis of data. Two examples are given to illustrate the change over time in power prices (seasonally and yearly).

E.1 Seasonal Partitions for Power Price Data

To look at the seasonal and yearly time effect upon power prices, a power price data set is partitioned by season and by year. Winter is defined as December 1 through February 28, or February 29 in a leap year, in the northern hemisphere, and June 1 through August 31 in the southern hemisphere. (Note that the winter period in the northern hemisphere and the summer period in the southern hemisphere is attributed to the year in which January and February occur, e.g. December 2000 and January and February of 2001 are referred to as Winter 2001 in the northern hemisphere.) Other seasons are similarly defined as three calendar month periods in this study.

A power price data set P is partitioned into subsets by year and by season, noted as SP_{pq}, where $p = 1, 2, 3$ and 4 is the index for season and is corresponding to Spring, Summer, Fall and Winter; $q = 1, 2, .., Q$ is the index of year, and Q is the number of total years that the power price data set P spans. One expected price velocity is calculated for each season, which is referred to as a seasonal expected price velocity (SEV). On any day in the subset P_{pq}, relating the SEV to the DAP on that day and subtracting it from the daily price velocity DVDA yields a unexpected price velocity UVDA on that day. Mathematically, if note:

p : the index of season, generally $p = 1, 2, .., 4$,

q : the index of year, generally $q = 1, 2, .., Q$,

k : the index of day, generally $k = 1, 2, .., K_{pq}$,

K_{pq} : the number of days in the subset SP_{pq},

SEV_p : the seasonal expected price velocity for the *p-th* season,

DAP_{pqk} : the daily average price on the *k-th* day in the subset SP_{pq},

$DVDA_{pqk}$: the price velocity on the *k-th* day in the subset SP_{pq},

$UVDA_{pqk}$: the unexpected price velocity on the *k-th* day in the subset SP_{pq},

then the unexpected price velocity is calculated as:

$$UVDA_{pqk} = DVDA_{pqk} - \frac{SEV_p}{DP_{pqk}} = DVDA_{pqk} - SEVDA_{pqk} ,$$

$$p=1,2,3,4;\ q=1,2,\ldots,Q;\ k=1,2,..,K_{pq},$$

where the SEVDA is the seasonal expected price velocity based on the DAP. Note that the unexpected price velocity UVDA can have negative values, when the price velocity DVDA is less than that expected from the seasonal average diurnal pattern. Figure E-1 gives an illustration of this partition.

$$\begin{array}{c} \textit{Power Price} \\ P = \left[\begin{pmatrix}(SP_{11})\\(SP_{22})\\ \\ (SP_{1Q})\end{pmatrix} \begin{pmatrix}(SP_{21})\\(SP_{22})\\ \\ (SP_{2Q})\end{pmatrix} \begin{pmatrix}(SP_{31})\\(SP_{32})\\ \\ (SP_{3Q})\end{pmatrix} \begin{pmatrix}(SP_{41})\\(SP_{42})\\ \\ (SP_{4Q})\end{pmatrix} \right] \left| \begin{array}{l}\textit{Year 1}\\ \textit{Year 2}\\ \\ \textit{Year Q}\end{array}\right. \\ \underbrace{SEV_1 \qquad SEV_2 \qquad SEV_2 \quad SEV_4}_{\textit{Seasonal Expected Price Velocity}} \end{array}$$

Figure E-1 Seasonal Partitions for Power Price Data.

E.2 An Example of Time Effect on Power Prices in Alberta

For the hourly power prices in Alberta between January 2000 and December 2002, a data partition, shown in Table E-1, divides the data set into 12 seasonal subsets. For each season there are three subsets, for example, three subsets Winter 2000, Winter 2001 and Winter 2002 for winter. Note that power prices in Winter 2000 spans December 1999, January and February 2000. December 1999 is the right preceding month of the studied period. For any uncompleted one-month-less season, one right preceding or following month, if available, will be recruited to make a full three-month season, whereas any uncompleted two-month-less season will be ignored. The power prices of the last month, December 2002, will, therefore, be attributed to Winter 2003, which is not included in this example.

Table E-1 Data Partitions Used in Alberta

Winter		**Spring**		**Summer**		**Fall**	
Winter 2000	December 1999	**Spring 2000**	March 2000	**Summer 2000**	June 2000	**Fall 2000**	September 2000
	January 2000		April 2000		July 2000		October 2000
	February 2000		May 2000		August 2000		November 2000
Winter 2001	December 2000	**Spring 2001**	March 2001	**Summer 2001**	June 2001	**Fall 2001**	September 2001
	January 2001		April 2001		July 2001		October 2001
	February 2001		May 2001		August 2001		November 2001
Winter 2002	December 2001	**Spring 2002**	March 2002	**Summer 2002**	June 2002	**Fall 2002**	September 2002
	January 2002		April 2002		July 2002		October 2002
	February 2002		May 2002		August 2002		November 2002

E.2.1 Comparison between Years

Seasonal diurnal patterns in summer in Alberta are shown Figure E-2; the AWDDP on weekdays in the left panel and the AWEDP on weekends in the right panel, and Table E-2 shows the corresponding seasonal average prices. It is evident that in the summer of 2000 Alberta saw significantly higher power prices

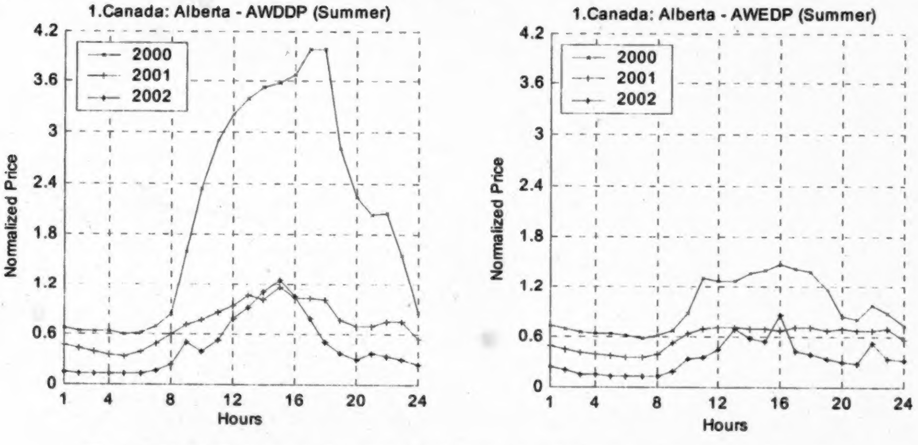

Figure E-2 Seasonal Diurnal Patterns in Three Summers in Alberta.

Table E-2 Seasonal Average Prices in Three Summers in Alberta

	Seasonal Average Price	
Season	**Weekday**	**Weekend**
Summer 00	2.05	0.96
Summer 01	0.72	0.58
Summer 02	0.45	0.34

in the mid-day on weekdays. During the peak hours on weekdays, i.e., 5 P.M. and 6 P.M., the power prices were, on average, over 4 times the OAP, and the seasonal average power price in 2000 was about 3 times that in 2001, and 5 times that in 2002. However, comparing to 2001 and 2002, this high price swings on weekdays did not produce significantly high unexpected price velocity UVDA, as shown in the upper left panel of Figure E-3. On weekends, the power prices in 2000 were slightly higher than that in the other two years, which generated significantly higher unexpected price velocity UVDA, as shown in the upper right panel of Figure E-3. About 25% of the days, the unexpected price velocity UVDA was greater than 0.2hr^{-1}, whereas this was the case on fewer than 20% of the days in other two years. The high prices on weekdays and the high-unexpected price velocity on weekends did not produce significantly high-unexpected price velocity in the summer of 2000, as shown in the lower panel in Figure E-3. It can be concluded that in the summer of 2000, Alberta suffered high power prices, but not high-unexpected price velocity on weekdays; and slightly high power prices, but high-unexpected price velocity on weekends.

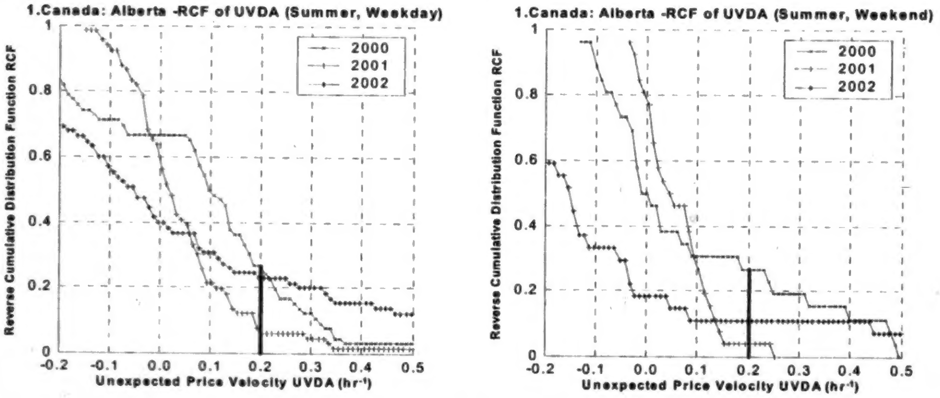

Figure E-3 Reverse Cumulative Distribution Function (RCF) of Unexpected Price Velocity UVDA in Three Summers in Alberta.

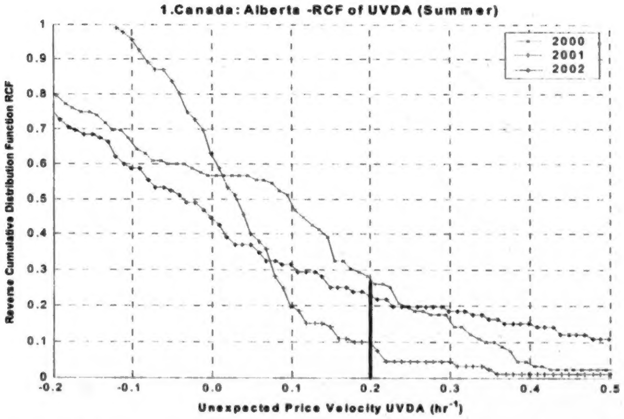

Figure E-3 Reverse Cumulative Distribution Function (RCF) of Unexpected Price Velocity UVDA in Summer in Alberta (Continued).

E.2.2 Comparison between Seasons

Similar comparisons can be made between seasons. The same data of four seasons in 2000 in Alberta is shown in Figures E-5 and E-6; and Table E-3. On weekdays, the power prices in the summer and the fall were much higher than that in the other two seasons. In the fall the power prices bore more intraday variation generating high-expected price velocity, but not high-unexpected price velocity. These two seasons did not have higher unexpected price velocity, rather the spring showed the higher unexpected price velocity. On weekends,

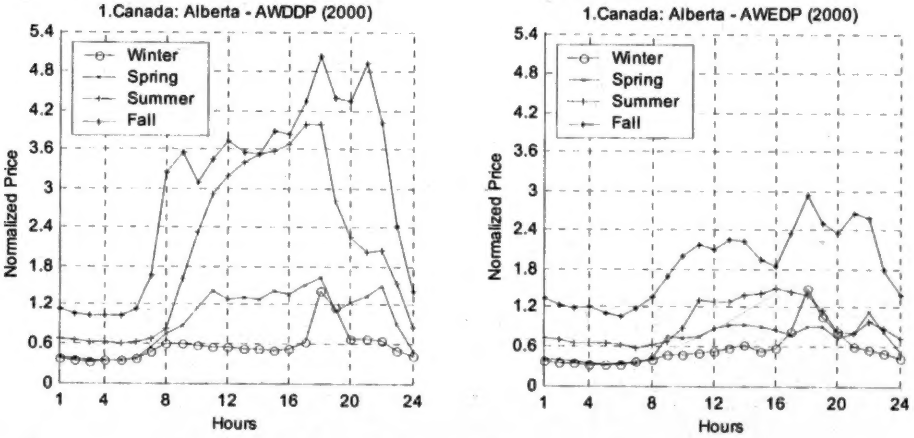

Figure E-4 Seasonal Diurnal Patterns in 2000 in Alberta.

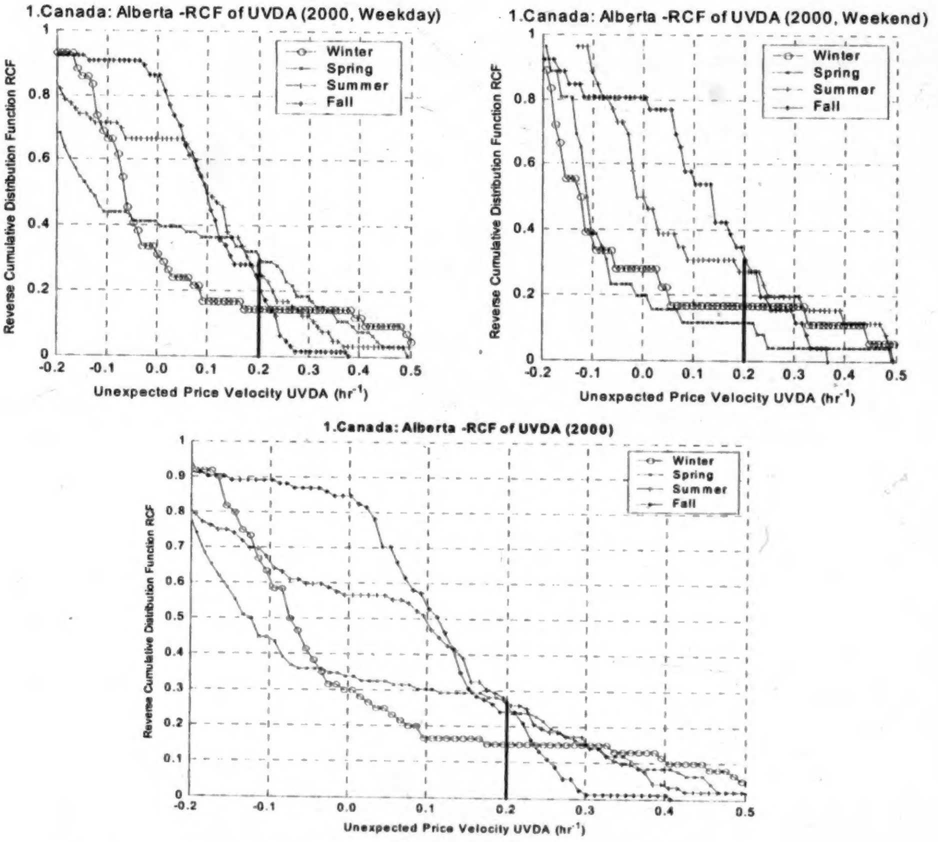

Figure E-5 Reverse Cumulative Distribution Function (RCF) of Unexpected Price Velocity UVDA in 2000 in Alberta.

Table E-3 Seasonal Average Prices in 2000 in Alberta

Season	Seasonal Average Price	
	Weekday	Weekend
Winter 00	0.57	0.55
Spring 00	0.97	0.68
Summer 00	2.05	0.96
Fall 00	2.95	1.86

power prices in the fall were visibly higher with a seasonal average price more than two times that of the other three seasons, and also a high-unexpected price velocity. In 2000, Alberta had high prices in the summer and the fall, but did not have significantly highly unexpected price velocity.